

***United States Court of Appeals
for the Second Circuit***



APPENDIX

77-6049

UNITED STATES COURT OF APPEALS
FOR THE SECOND CIRCUIT
Docket No. 77-6049

County of Suffolk, County of Nassau,
Town of Islip, Town of Hempstead,
Town of North Hempstead, Town of
Oyster Bay, Town of Huntington,
and the Board of Trustees of the
Town of Huntington and Concerned
Citizens of Montauk, Inc.,

Appellees,

- against -

Secretary of the Interior, et al.,

Appellants,

National Ocean Industries Association,
et al.,

Intervenor-Appellants.

The Natural Resources Defense Council, Inc.,

Appellees,

- against -

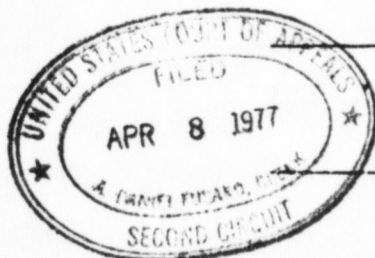
Thomas S. Kleppe, Secretary of the Interior,

Appellant,

National Ocean Industries Association, et al.,

Intervenor-Appellants.

On Appeal from the United States District
Court for the Eastern District of New York



JOINT APPENDIX
(Volume V 2531 - 3087)

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Eastern District of New York
Attorney for Appellant
Secretary of Interior

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Department of Interior to adopt an accelerated oil and gas leasing program of the Outer Continental Shelf and specifically seek to enjoin bidding on OCS Lease Sale No. 35, the first sale under this plan, scheduled to occur on December 11, 1975. Plaintiffs include the Southern California Association of Governments, the County of Los Angeles and the People of the State of California. Western Oil & Gas Association and various oil companies intervene in this action as defendants.

This important case, filed just a week ago, is currently before the Court on plaintiffs' motions for preliminary injunction, seeking to enjoin the bidding scheduled to open on December 11, 1975. After review of the voluminous briefs filed by counsel in this action, and in light of the factors to be considered as set forth in Virginia Petroleum Jobbers Ass'n v. Federal Power Commission, 104 U.S. App. D.C. 106, at 110, 259 F.2d 921, at 925 (1958), the Court concludes that plaintiffs' motions must be denied on the grounds that there is no showing-by plaintiffs in this action of any likelihood of success on the merits.

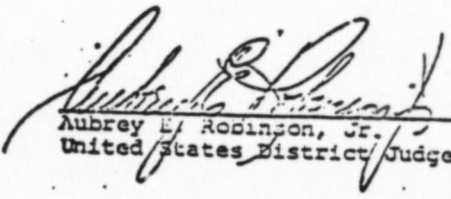
A threshold consideration of res judicata and the related issue of collateral estoppel arises out of the recent case of People of the State of California v. Morton, (D.C.D. Cal. No. CV 74-2374-DWW) decided November 17, 1975. In that case Judge David W. Williams, in a memorandum opinion issued after trial, determined, inter alia, the sufficiency of the various environmental impact statements challenged herein and the inappropriateness of enjoining Lease Sale No. 35. The government argues persuasively that all plaintiffs in this action are bound by Judge Williams' determination.

Additionally the action of plaintiffs People of the State of California in recently filing a Rule 52(a) Motion to Make Additional Findings of Fact and Conclusions of Law in that case, combined with their failure to file a Rule 59 Motion for New Trial or Notice of Appeal, raises a serious question concerning the propriety of this Court's consideration of this action under principles of comity.

The above matters are not dispositive, however. The Court has, in addition, reviewed the various arguments asserted by plaintiffs in support of their request for preliminary relief and fails to find the sufficiency of a likelihood of success on the merits to warrant imposition of injunctive relief at this time.

Upon the foregoing, it is this 5th day of December, 1975,

ORDERED that Plaintiffs' Motions for Preliminary Injunction be and hereby are DENIED.


Aubrey E. Robinson, Jr.
United States District Judge

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HymanUNITED STATES DISTRICT COURT
EASTERN DISTRICT OF NEW YORKCOUNTY OF SUFFOLK, COUNTY OF NASSAU,
TOWN OF ISLIP, TOWN OF HEMPSTEAD, TOWN
OF NORTH HEMPSTEAD, TOWN OF OYSTER BAY,
TOWN OF HUNTINGTON, and the BOARD OF
TRUSTEES OF THE TOWN OF HUNTINGTON,

Plaintiffs,

-against-

SECRETARY OF THE INTERIOR and CURTIS J.
BERKLUND, individually and as Director
of the Bureau of Land Management,

Defendants.

Civil Action

No. 75 C 208

THE STATE OF NEW YORK and THE NATURAL
RESOURCES DEFENSE COUNCIL, INC.,

Plaintiffs,

-against-

THOMAS S. KLEPPE, Secretary of the
Interior,

Defendant.

Civil Action

No. 76 C 1229

CITY OF WASHINGTON }
DISTRICT OF COLUMBIA }AFFIDAVIT OF STANLEY D. DOREMUS

Stanley D. Doremus, being duly sworn, deposes and states the following:

1. I am currently Deputy Assistant Secretary of the Interior for Program Development and Budget. During all times material to this affidavit, I have held the position of either Deputy Assistant Secretary or Acting Deputy Assistant Secretary, I share the responsibility for supervising the Office of OCS Program Coordination, and in this capacity I am familiar with the administration of Outer Continental Shelf (OCS) oil and gas leasing under the OCS Lands Act, 43 U.S.C. §§ 1331-1343 (1970). Additionally, in my positions I have personal knowledge of the preparation and filing of environmental impact statements (EISs) for the OCS program pursuant to the

National Environmental Policy Act of 1969 (NEPA), 42 U.S.C. 4321 et seq. (1970). This affidavit is based upon personal knowledge, records of the Department of the Interior, and information derived from departmental staff, including officials of the Office of the Solicitor.

OCS Oil and Gas Lease Termination and Suspension

2. In the course of the Department's OCS planning and operations effort, the issue as to whether or not the Secretary of the Interior has the power to cancel or terminate a lease, once issued, if he determines that an environmental hazard poses an unacceptable threat to persons, property, and natural resources has been fully explored.

3. Cancellation of an OCS oil and gas lease is expressly provided in the OCS Lands Act. Section 5(b) of the Act (43 U.S.C. 1334(b)) states when a lease may be cancelled. When the owner of the lease "fails to comply with any of the provisions of this Act, or of the lease, or of the regulations issued under this Act and in force and effect on the date of issuance of the lease. . .," the lease may be cancelled either administratively under section 5(b)(1) (43 U.S.C. 1334(b)(1)) when it is nonproducing, or by judicial action under section 5(b)(2) (43 U.S.C. 1334(b)(2)) when it is producing. This cancellation authority is explicitly tied to noncompliance by a lessee.

4. In its consideration of this termination question, the Department has legally determined that: (1) an OCS oil and gas lease must be issued for five years and as long thereafter as oil and gas may be produced from the area in paying quantities, pursuant to section 8(b)(2) of the OCS Lands Act (43 U.S.C. 1337(b)(2)); and (2) an OCS oil and gas lease may be cancelled only upon the lessee's failure to comply with the provisions of the OCS Lands Act, the regulations in force and effect at the time the lease is issued, and the lease itself, and not upon the occurrence of an event which does not involve the lessee's default, e.g., the discovery of previously unknown environmental dangers.

5. However, the Secretary is given wide authority under section 5(a) of the OCS Lands Act (43 U.S.C. 1334(a)) to issue regulations in the interest of conservation of the natural resources of the OCS. These regulations are fully effective as to leases existing at the time such regulations are promulgated.^{1/} OCS leases provide that the leases are subject, inter alia, to regulations thereafter promulgated pursuant to section 5(a)(1) of the OCS Lands Act, supra, for the prevention of waste and for the conservation of natural resources. Such leases would also be subject to new or amended OCS operating orders which may be adopted to implement those regulations. The Secretary is specifically authorized under section 5(a)(1) to issue regulations for the suspension of operations. A suspension -- which gives promise of eventual development and would not be, in effect, a termination -- can be ordered in the interest of conservation of the natural resources of the OCS pursuant to that section. There is no time limit on a suspension for this purpose, but that of reasonableness.

6. The Secretary of the Interior has concluded that, while he does not have the legal authority to include in the leases a termination clause permitting him to cancel a lease for unforeseen environmental hazards, he does have the authority to provide for a suspension of operations in these circumstances. He has provided by regulation (30 CFR 250.12(c)) for the suspension of operations, including production, which threaten immediate, serious, or irreparable harm or damage to life, including aquatic life, to property, to lease deposits, to other valuable mineral deposits, or to the environment until such time as the responsible official determines that the threat or danger has terminated. For a discussion of the Secretary's continuing supervisory authority over OCS leases, including his suspension powers, see Sierra Club v. Morton, 510 F.2d 813 (5th Cir. 1975).

^{1/} Section 5(a)(1) provides as follows: "[t]he Secretary may at any time prescribe and amend such rules and regulations as he determines to be necessary and proper in order to provide for the prevention of waste and conservation of the natural resources of the outer Continental Shelf, . . . and, notwithstanding any other provisions herein, such rules and regulations shall apply to all operations conducted under a lease issued or maintained under the provisions of this Act."

7. Moreover, if, after lease issuance, environmental information should become available or new technology developed, departmental regulations can be issued to require additional safeguards or new technology where such requirements are in the interest of conservation of the natural resources of the OCS.

8. OCS operating orders implement departmental regulations, and significant violations of such orders can subject the lease to the cancellation provisions of the Act. (See 30 CFR 250.30 and 250.80.) For example, a continued failure to control pollution from known potential sources of pollution, which is subject to control under prevailing practices and technology would constitute a violation of OCS operating orders and regulations, and would subject the OCS lease to the cancellation provisions of the OCS Lands Act.

9. Policy officials of the Department, on the advice of the Solicitor's Office, the Department's legal office, have administered and supervised the OCS leasing program on the understanding that the Secretary of the Interior, while possessing powers to suspend lease operations in the circumstances referred to in paragraphs 5 and 6 above, does not possess the legal power to terminate such leases.

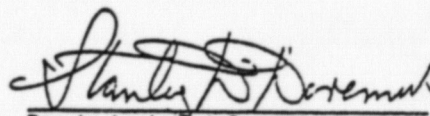
10. Plaintiffs, in the case of Southern California Association of Governments, et al. v. Kleppe, et al., Civil Action No. 75-1942, and consolidated cases,^{2/} which were recently before the United States District Court for the District of Columbia, raised the issue of the existence of such a power in the Secretary of the Interior and attacked his failure to include such a termination provision in OCS leases for an OCS lease sale offshore

^{2/} Civil Action Nos. 75-1943, 75-1962, and 75-2044.

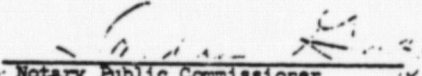
southern California. On December 5, 1975, the court, after considering all the issues raised, including the termination issue, denied plaintiffs' request for preliminary injunction.^{3/}

Finally, under the Department's continuing supervision of OCS oil and gas lease operations, lessees must obtain the specific approval of the Area Oil and Gas Supervisor of the Geological Survey before commencing activities at each stage of lease operations. For example, lessees must receive approval of exploratory drilling plans (30 CFR 250.34(a)(d) and (e), as amended, 40 F.R. 51199-51200 (November 4, 1975)); approval of development plans (30 CFR 250.34(b) - (e), as amended (see above)); grants of rights of use or easements, subject to conditions prescribed by the Supervisor, to construct and maintain platforms, fixed structures, artificial islands, and pipelines, for use in carrying on operations (30 CFR 250.18); approval of the design, other features, and plan of installation of all platforms, fixed structures and artificial islands (30 CFR 250.19(a)); approval of the design, other features, and plan of installation of all pipelines for which a right of use or easement has been granted under 30 CFR 250.18(c), including portions of such lines which extend onto or traverse areas other than the OCS (30 CFR 250.19(b)).

Dated this 3rd day of August 1976.


Deputy Assistant Secretary
Program Development and Budget
Department of the Interior

SUBSCRIBED and SWORN to before me this 2nd day of ~~xxxxxx~~ 1976.


Notary Public Commissioner
My Commission expires: 1-1-77

^{3/} These cases were transferred to the Central District of California, and, on July 19, 1976, the court dismissed the actions brought by the State of California, the Southern California Association of Governments, and the County of Los Angeles. The court has ordered further briefing on the dismissal issue as to American Littoral Society, et al. v. Klappe.

1 UNITED STATES DISTRICT COURT
2 EASTERN DISTRICT OF NEW YORK

3 COUNTY OF SUFFOLK, et al.,

4 Plaintiffs,

5 -against-

6 SECRETARY OF THE INTERIOR, et al.,

7 Defendants.

Civil Action

No. 75 C 208

8 THE STATE OF NEW YORK, et al.,

9 Plaintiffs,

10 -against-

11 THOMAS S. KIEPPE, Secretary of the Interior,

12 Defendant.

Civil Action

No. 76 C 1229

13 CITY OF WASHINGTON)

14 DISTRICT OF COLUMBIA)

15 Affidavit of Alan D. Powers

16 ALAN D. POWERS, being duly sworn, deposes and states the following:

17 1. I am the Director, Office of Outer Continental Shelf (OCS)
18 Program Coordination, which is under the supervision of the Assistant
19 Secretary of the Interior for Program Development and Budget. I assumed
20 this position on February 29, 1976. In my capacity as Director, Office of
21 OCS Program Coordination, I am familiar with the administration of Outer
22 Continental Shelf oil and gas leasing under the OCS Lands Act, 43 U.S.C.
23 1331-1343 (1970). I have personal knowledge of the preparation and filing
24 of environmental impact statements (EISs) for the OCS program pursuant to
25 the National Environmental Policy Act of 1969 (NEPA), 42 U.S.C. 4321 et seq.
26 (1970), including the EIS for the proposed OCS general oil and gas lease
27 sale of lands offshore the mid-Atlantic states (OCS Lease Sale No. 40).
28 This affidavit is based upon personal knowledge, records of the Department
29 of the Interior, and information derived from departmental staff.

30 2. The procedures followed by the Department of the Interior
31 in considering OCS lease sale proposals and the early stages of the
32

1 consideration of the proposed OCS lease sale of lands offshore the
2 mid-Atlantic states have been discussed in affidavits filed with this
3 court earlier. The consideration given to the mid-Atlantic OCS lease
4 sale proposal since January 16, 1976, will be discussed below.

5 3. Public hearings were held on the site-specific draft EIS
6 for the proposed OCS oil and gas lease sale of lands offshore the mid-
7 Atlantic states in Atlantic City, New Jersey, on January 27, 28, 29, and 30,
8 1976. The hearing record contains the testimony of 137 persons during
9 approximately 26 hours of testimony over the 4-day period, and totals 952
10 pages.

11 4. The Department also received some 185 letters of comment on
12 the lease sale proposal in the comment period provided before and after the
13 public hearings.

14 5. Thereafter, the Bureau of Land Management (BLM) proceeded
15 to revise the draft EIS in light of the comments received at the public
16 hearings and all of the written comments submitted to the Department.

17 6. On May 26, 1976, BLM submitted to the Council on Environmental
18 Quality (CEQ) and made available to governmental agencies and the public a
19 final EIS for the mid-Atlantic OCS lease sale proposal pursuant to NEPA.

20 7. During the late stages of preparing the final EIS, BLM began
21 preparation of a program decision option document (PDOD) for this OCS lease
22 sale proposal.

23 8. On June 16, 1976, a proposed PDOD for the OCS lease sale
24 proposal No. 40 was circulated by the Assistant Secretary - Program Develop-
25 ment and Budget, to Assistant Secretaries and Bureau heads involved in the
26 OCS leasing program. The covering memorandum requested the comments and
27 recommendations of the officials referred to above with respect to the PDOD
28 and the options available to the Secretary in deciding whether or not to hold
29 a lease sale of lands offshore the mid-Atlantic states.

30 9. On June 22, 1976, the Assistant Secretary - Program
31 Development and Budget submitted to the Secretary a memorandum requesting
32

1 a decision on the BLM proposal for OCS Lease Sale No. 40. The following
2 documents were attached to the June 22 memorandum for the Secretary's con-
3 sideration and evaluation:

4 a. Final EIS prepared by BLM.

5 b. PDOD prepared by BLM.

6 c. Views and recommendations of the following departmental
7 officials:

8 (1) Assistant Secretary - Program Development and Budget
9 (June 21, 1976).

10 (2) Acting Assistant Secretary - Land and Water (June 18, 1976).

11 (3) Assistant Secretary - Energy and Minerals (June 21, 1976).

12 (4) Deputy Assistant Secretary - Management (June 18, 1976).

13 (5) Director, BLM (June 18, 1976).

14 (6) Director, Geological Survey (June 18, 1976).

15 (7) Acting Deputy Associate Director, Fish and Wildlife Service,
16 and Assistant Secretary, Fish and Wildlife and Parks (June 21,
17 1976).

18 (8) Associate Director, Park System Management, and Assistant
19 Secretary, Fish and Wildlife and Parks (June 18, 1976).

20 The following documents were submitted by the Assistant Secretary -
21 Program Development and Budget to the Secretary on June 25, 1976, for his con-
22 sideration and evaluation:

23 d. Memorandum from Assistant Secretary - Program Development and
24 Budget to the Secretary dated June 25, 1976, concerning options for
25 higher royalty rates for selected tracts for proposed OCS Sale No.
26 40, Mid-Atlantic.

27 e. Memorandum from Director, Geological Survey, to Assistant Secre-
28 tary - Program Development and Budget dated June 25, 1976, concerning
29 potential geologic hazards, OCS Sale No. 40, Mid-Atlantic.

30 10. The Secretary considered and evaluated the documents referred to
31 in paragraph 9a-c during the period from June 22, 1976, to June 28, 1976, and
32 paragraph 9d and e during the period from June 25, 1976, to June 28, 1976.

1 11. On June 28, 1976, a decision meeting was held on the OCS oil and
2 gas Lease Sale No. 40, during which the Secretary was briefed by departmental
3 staff on issues discussed in the final EIS and the PDOD, and the options
4 available to him in deciding whether or not to hold a mid-Atlantic OCS lease
5 sale.

6 12. At the conclusion of the June 28 decision meeting, the
7 Secretary decided to approve OCS Lease Sale No. 40.

8 13. On June 30, 1976, the Secretary publicly announced his
9 decision to approve OCS Lease Sale No. 40 to be held on August 17, 1976.

10 14. OCS Lease Sale No. 40 involves the offering of 154 tracts,
11 totalling 876,750 acres on the OCS in the Baltimore Canyon Trough offshore
12 New Jersey and Delaware. In deciding to hold this sale, the Secretary gave
13 careful consideration to the final EIS issued May 26, 1976, consulted with
14 officials of states which would be affected by the sale, and with environ-
15 mental and other groups. He determined that the risk to the environment
16 accompanying oil and gas development in the mid-Atlantic would be relatively
17 minor. (See Exhibit 1.)

18 15. The Secretary also ordered the imposition of special lease
19 stipulations designed to mitigate potential environmental and socioeconomic
20 effects of offshore development. Stipulations pertaining to all leases are
21 intended to help the mid-Atlantic states plan for onshore development. One
22 stipulation requires that lessees notify governors of the mid-Atlantic
23 states regarding the onshore impacts of exploratory activities. Another
24 stipulation will preserve the right of the Department to require that pipe-
25 lines be placed in designated corridors and, wherever technically and
26 economically feasible, require pipeline burial. Other stipulations are designed
27 to protect archeological, cultural, and biological resources and to minimize
28 oil transport by tankers. (See Exhibit 1.)

29 16. Fifteen of the tracts involved in the lease sale will be
30 offered for sale at 33-1/3 percent royalty, and the remaining 139 tracts
31 will be offered at the customary 16-2/3 percent royalty. Advantages of using
32

1 a higher royalty rate lie in the fact that bidding companies usually reduce
2 the size of the bonus bid to reflect the rate of flow to the federal govern-
3 ment if and when oil and gas deposits are discovered and the tract is developed.
4 Thus, initial cost may be reduced which better enables smaller operators to
5 compete in the bidding. Higher royalty rates also may provide a larger
6 return to the government in the long term if exploration proves successful.
7 (See Exhibit 2.)

8 17. On July 12, 1976, final OCS operating orders covering
9 exploratory activities on any leases to be issued in the mid-Atlantic OCS
10 area were published by the U.S. Geological Survey (41 F.R. 28553). Final
11 OCS orders concerning lease development and production activities will be
12 published at a later date, but prior to any development activities on any
13 lease that may be issued.

14 18. On July 16, 1976, the BLM published a notice of oil and gas
15 Lease Sale No. 40, August 17, 1976, which described the terms of the lease
16 offering and the lease terms and stipulations that will be included in any
17 lease issued as a result of that sale.

18 19. In arriving at a decision to hold OCS Lease Sale No. 40, the
19 Secretary was just as sensitive to environmental concerns as in his two
20 previous OCS lease sale decisions for the southern California and Gulf of
21 Alaska OCS areas. (See Exhibits 1, 2, 3, and 4.) He carefully considered
22 the potential adverse environmental impacts associated with the mid-Atlantic
23 OCS oil and gas lease sale and the alternatives to that sale, as reflected
24 in the final EIS for the lease sale proposal. It was his judgment, however,
25 and it continues to be his judgment that the environmental hazards posed by a
26 mid-Atlantic OCS oil and gas lease sale were not sufficient to require a
27 withdrawal or substantial modification of the lease sale proposal. This is
28 the essence of the advice and recommendations he received from departmental
29 policy officials. The same view of the potential environmental risks was
30 reflected in the comments of federal agencies such as the Environmental
31 Protection Agency and CEQ.
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Dated this 3rd day of August, 1976.

SUBSCRIBED and SWORN to before me this 3^d day of August, 1976.

6

DEPARTMENT of the INTERIOR

BUREAU OF LAND MANAGEMENT

Robinson (202) 343-5717

For Release June 30, 1976

news release

2544

INTERIOR ANNOUNCES SALE DATE OF AUGUST 17 FOR OCS (#40) SALE IN MID-ATLANTIC

A lease sale of 154 tracts totaling 876,750 acres on the Outer Continental Shelf (OCS #40) in the Baltimore Canyon Trough offshore New Jersey and Delaware will be held in New York City on August 17, 1976, Secretary of the Interior Thomas S. Kleppe announced today.

Secretary Kleppe said he decided to move ahead with the sale after careful consideration of the final environmental impact statement, issued May 26, consultations with the States which will be affected, and with environmental and other groups.

"The risk to the environment accompanying oil and gas development in the Mid-Atlantic is relatively minor," the Secretary said.

The estimated hydrocarbon resource potential involved in the sale totals between 400 million to 1.4 billion barrels of oil and 2.6 to 9.4 trillion cubic feet of gas.

If oil and gas resources are found in the area, production is expected to begin in 1981 with peak production occurring in 1989 or 1990.

The 154 tracts being offered lie in water depths from 131 to 607 feet and are 47 to 92 miles from shore.

It is planned to offer 15 tracts on the basis of a 33 1/3% royalty, rather than the 16 2/3% royalty rate that has been used in most OCS sales. However, the balance of the tracts will be offered at the 16 2/3% royalty rate. Details, including the tract numbers of tracts to be offered at the higher rate, will be provided in the sale notice.

Interior's Bureau of Land Management will conduct the sealed bid auction, the first in the Atlantic seaboard area.

Notice of the sale will be published in the Federal Register in mid-July, with full details of the actual tracts to be offered for sale and the lease restrictions designed to assure adequate protection of both the marine and on-shore environment.

There are special lease stipulations designed to mitigate potential environmental and socio-economic effects of offshore development.

Stipulations pertaining to all leases are intended to help the Mid-Atlantic States plan for onshore development. For example, lessees and operators are required to submit their development plans to the States for review. Sale #40 also includes a stipulation requiring that lessees notify Governors of the Mid-Atlantic States regarding the onshore impacts of exploratory activities. Other stipulations are designed to protect archeological, cultural and biological resources; and to minimize oil transport by tankers.

(more)

A key stipulation would preserve the right of the Department to require that pipelines be placed in designated corridors; and require pipeline burial.

Secretary Deppe also announced that he had decided not to waive the ban on joint bidding by major oil companies for the lease sale in the Baltimore Canyon Trough. Under the 1975 Energy Policy Conservation Act, he has the authority to waive the ban on joint bidding in areas of high environmental risk or of high exploratory drilling and development costs.

Companies with average daily production of crude oil, natural gas, or liquified petroleum products exceeding 1.6 million barrels worldwide are banned from bidding with each other, but may continue to bid jointly with smaller companies. Nine major oil companies are currently banned from bidding jointly with each other under the regulation.

The Secretary said that the desirability of fostering competition, by encouraging more producers to bid independently in the Baltimore Canyon Trough lease sale, outweighed other factors.

Interior's Bureau of Land Management took the first step involving public participation in Federal OCS decision making for the proposed Mid-Atlantic lease sale on March 25, 1975, when it issued a Call for Nominations and Comment.

The area of the call was for 6.5 million acres. Twenty companies nominated 557 tracts totaling 3.2 million acres.

Since then, a 26-company consortium has underwritten a \$15 million off-structure stratigraphic test drilling venture under a permit from the U.S. Geological Survey to gather geologic information on subsea oil and gas deposits on the Baltimore Canyon Trough.

When Interior on August 20, 1975, announced the 154 tracts selected for intensive environmental study, the nominated area was reduced to 876,750 acres.

Seventy-one tracts were eliminated from consideration at the request of the commercial fishing industry, a decision supported by the U.S. Fish and Wildlife Service in Interior, the National Marine Fisheries Service in the National Oceanic and Atmospheric Administration (NOAA), and the views of Coastal States.

State government representatives from New Jersey, New York, Delaware, Maryland, and Virginia were present at the formal meetings of BLM, U.S. Geological Survey and the Fish and Wildlife Service when the tract selection recommendations were developed.

A Draft Environmental Impact Statement was developed covering the 154 tracts, and public hearings were held in Atlantic City, New Jersey, January 27 through 30, 1976.

A Final EIS was published May 26, 1976, and submitted to the President's Council on Environmental Quality (CEQ) for 30-day review, which expired on June 25, 1976. The Final EIS reflected the oral testimony at the hearing, written submission to the record, and the views of coastal States and other Federal officials.

Powers Affidavit

Exhibit No. 2

DEPARTMENT of the INTERIOR

2546

news release

BUREAU OF LAND MANAGEMENT

For Release July 16, 1976

Robinson (202) 343-5717

BLM ANNOUNCES SALE OF OIL AND GAS LEASES IN BALTIMORE CANYON TROUGH (OCS #40) AUG. 17

A sale of oil and gas leases on the Baltimore Canyon Trough Outer Continental Shelf (OCS #40) will be held in the Grand Ballroom of the Statler-Hilton Hotel, Seventh Avenue at 32nd to 33rd Streets, New York City, on August 17, 1976, Secretary of the Interior Thomas S. Kleppe announced today.

Interior's Bureau of Land Management will conduct the sealed bid auction, the first frontier OCS area to be offered for lease sale along the Atlantic seaboard. Bid opening will begin at 10 a.m., EST.

Secretary Kleppe responded July 13 to a request from Rep. John M. Murphy, Chairman of the House Ad Hoc Select Committee on the Outer Continental Shelf, that the Department delay the Mid-Atlantic sale until Congress has completed its consideration of bills H.R. 6218 and S. 521 to amend the Outer Continental Shelf Lands Act of 1953.

"I have given your requests a great deal of thought and have concluded that it would not be in the national interest to delay implementation of our OCS program," Secretary Kleppe said. "In July of 1975 and on several other occasions, you have made similar requests to delay leasing in frontier areas until new legislation is enacted. It now seems clear that such a delay would have been unwise, since legislation still has not been enacted and signed into law by the President nor is it certain that these events will take place.

"If the present leasing program were seriously deficient and the bills now under consideration would clearly improve it, there would be a basis for delay, but in my opinion neither is the case. Furthermore, if legislation is finally enacted, many of the provisions being discussed would be fully effective on leases already issued. This is true of oil spill liability, safety regulations, and development plans, to name just a few."

The Secretary said he also believes that the OCS program as currently constituted provides the coastal States adequate protection from adverse impacts of offshore development. "We have worked closely with the affected State governments throughout all phases of the process and have taken steps to ensure that the States have adequate information to meet their onshore planning and land use responsibilities both at the exploration and development stages," he said.

(more)

"For these reasons," he said, "I cannot in good conscience delay the Mid-Atlantic sale or delay consideration of leasing in other frontier areas. It is essential that we take all reasonable efforts to reduce reliance on expensive and insecure foreign imports. The leasing program as presently constituted is sound and is operating in the public interest."

Notice of the sale is being published in the Federal Register July 16, 1976, along with full details of the actual tracts to be offered for sale, and lease stipulations designed to assure adequate protection of the environment.

The submerged lands on the Federal OCS to be offered for sale lie off the coasts of the States of New Jersey and Delaware from 47 to 92 miles from shore in waters from 131 to 607 feet deep. A total of 154 tracts covering 876,750 acres (354,816 hectares) will be offered for lease sale in Outer Continental Shelf Sale #40.

Fifteen of the tracts will be offered for sale at 33 1/3 percent royalty, and the remaining 139 tracts will be offered at the customary 16 2/3 percent royalty.

Advantages of using a higher royalty rate lie in the fact that bidding companies usually reduce the size of the bonus bid to reflect the greater flow of revenue to the Federal government if and when oil and gas deposits are discovered and the tract is developed. Thus, initial costs may be reduced which better enables smaller operators to compete in the bidding. Higher royalty rates also may provide a larger return to the government in the long term, if exploration proves successful.

New lease stipulations deal with notification to State governors of onshore impacts of exploratory activities, minimizing crude oil transport by tankers, controls on industry radio communications to avoid interference with shore military installations, and unexploded ordnance on the seabed floor.

Conventional stipulations include pollution prevention, archaeological and historical examination and surveillance, and measures to minimize the dangers of mass movements of seabed sediments.

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Powers Affidavit

Exhibit No. 3

DEPARTMENT of the INTERIOR

2548

news release

OFFICE OF THE SECRETARY

For Immediate Release October 31, 1975

ENVIRONMENTAL CONCERNS PROMPT MODIFICATION OF SOUTHERN CALIFORNIA OCS SALE

Secretary of the Interior Thomas S. Kleppe today approved a modified oil and gas lease sale on the Southern California Outer Continental Shelf. The sale, originally proposed to include tracts totaling 1.6 million acres, was limited by Kleppe to approximately 1.25 million acres. The sale is now scheduled to be held in Los Angeles on December 9, 1975.

Covered in the sale will be selected areas from Point Mugu south to Dana Point, and extending seaward beyond the Santa Barbara Channel Islands, Santa Barbara Island, and San Clemente Island. Kleppe's decision eliminated from the earlier sale proposal all tracts in the Santa Monica Bay area, as well as tracts south of San Miguel Island. No tracts in the Santa Barbara Channel will be leased. Kleppe also has decided to provide an additional Federal buffer zone around the normal three-mile zone of State waters. This Federal buffer zone would extend another three quarters of a mile around State waters in all areas of the sale, except those adjacent to State-leased tracts.

"Our decision is based upon the urgent need to develop available domestic energy resources, and upon the legitimate environmental concerns raised by public comments and government officials," Kleppe said. "We therefore have decided to modify significantly the original proposal to afford extra protection for the scenic and wildlife values of the southern California area."

The Secretary also announced that three tracts in the San Pedro Bay area will be offered at a 33 1/3 percent royalty rate intended to reduce the front end capital requirements of the bidding participants, rather than the normal 16 2/3 percent rate. This program modification, coupled with an earlier Department prohibition against joint bidding by major oil companies, is designed to increase competition by making it more attractive for smaller companies to participate.

In areas of critical environmental concern, lease stipulations will require that each platform maintain oil containment equipment as an increased precaution against spills.

During the almost two years between Interior's call for nominations and comments from industry and the public on specific tracts that might be offered in a sale or excluded from leasing and the scheduled sale date, the Federal Government followed an orderly series of steps to comply with Federal statutes, guidelines, and regulations, while consulting with California city and State officials on various aspects of the leasing proposal.

(over)

Interior has coordinated with and obtained information and data from 26 Federal agencies, 18 California agencies, 25 county organizations (primarily from the five Southern California counties whose shorelines border the sale area), 22 cities, 38 private companies and organizations, 26 citizen and professional groups, two regional government agencies, 22 universities and research organizations, numerous U.S. Senators and Representatives, and several California State senators, assemblymen, and committees.

No other OCS sale is planned for 1975. So far, the Bureau of Land Management has leased in three sales this year a total of 1.5 million acres for development in the Gulf of Mexico. Other frontier OCS sale areas are tentatively scheduled, with the earliest being 1.8 million acres in the northern Gulf of Alaska (proposed OCS Sale #39) planned for January, 1976.

The Federal Register notice concerning the southern California sale will be published November . The Federal Register will list all conditions pertaining to the sale which will include special environmental stipulations, the list of tracts, and instructions for submission of bids.

Rawlins Affidavit

Exhibit no. 4

DEPARTMENT of the INTERIOR

2550

news release

OFFICE OF THE SECRETARY

Newman (202) 343-3171

For Release February 18, 1976

SECRETARY KLEPPE ANNOUNCES LIMITED OCS SALE IN NORTHERN GULF OF ALASKA

Secretary of the Interior Thomas S. Kleppe announced today in Fargo, North Dakota, that he has decided to move ahead with a sale of oil and gas leases in the Northern Gulf of Alaska (OCS-39) but to reduce substantially the acreage being offered in order to minimize environmental risks.

In a letter today to Russell W. Peterson, Chairman of the Council on Environmental Quality, Kleppe said: "I have decided that on balance it is in the National interest to move ahead with the lease sale, and I have directed that it be held as soon as our preparations are complete." Russell Train, Administrator of the Environmental Protection Agency, and Governor Jay S. Hammond of Alaska were also notified today of the Secretary's decision.

Kleppe said that he had concluded, following an extensive review of plans for the sale over the past two months, that it would not be in the public interest to lease all of the 1.8 million acres originally proposed and that he has directed that about 40 percent of the proposed acreage be eliminated. This would reduce the sale to about 1.1 million acres.

Secretary Kleppe stressed that he had spent many hours studying and hearing debate about which tracts to include and exclude from the sale in order to balance benefits and risks.

He said he had decided to eliminate the following groups of tracts:

- (1) All tracts west of Kayak Island except a group of sixteen along the northern tiers of the group originally proposed. "Our studies indicate that these sixteen are both promising for oil and gas discovery and environmentally less risky than other tracts in that area because of prevailing wind and current patterns," he said.
- (2) A group of tracts near the southeast corner of Kayak Island, in order to reduce the risk of impacts near both Middleton Island and the Copper River Delta.
- (3) Ten tracts in the southeast region of the sale area which have been identified as important commercial fishery spawning grounds.
- (4) Ten tracts which the U.S. Geological Survey advised may not be capable of safe development because of geologic hazards. For similar reasons a number of other tracts will be offered under special stipulations as to drilling and platform placement.

The Secretary said that while the sale is larger than recommended by CEQ, by far the most risky tracts have been removed, the remaining over-all probability of damaging accidents is low, and the potential value to the Nation of discoveries in this area is very high.

The Secretary said the Department's information on geologic hazards is already sufficient for the sale and that the Department would issue shortly in final form those operating orders which affect exploratory activity undertaken immediately after leasing.

"I have decided," Kleppe said, "to adopt a suggestion made by EPA to require that lessees in the Northeast Gulf of Alaska, in a supplement to their exploratory plans, provide information about their projected onshore activities which may be helpful to State and local jurisdictions in preparing for the onshore impacts of OCS leasing."

Secretary Kleppe said that based on bidding on 30 percent of the tracts offered, as was the case in the recent California sale, the sale is expected to result in high bonus bids totalling between \$500 million and \$1 billion.

The Bureau of Land Management has been directed by the Secretary to prepare a Notice of Sale which is expected to be issued late this month. This notice will specify the tracts being offered, special sale stipulations, and the date and place of the sale.

The text of the Secretary's letter to Paterson is attached.

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United States Department of the Interior

OFFICE OF THE SECRETARY
WASHINGTON, D.C. 20240

FEB 17 1976

Dear Russ:

Since January 23, when John Busterud, acting for you, forwarded recommendations concerning the Northeast Gulf of Alaska outer continental shelf lease sale, we in Interior have conducted an extensive review of the matter, and have given detailed consideration to your concerns. As I am sure you recognize, the best course of action is not easy to determine; this is an especially difficult instance of the problem of balancing two of the Nation's highest priorities, energy supply and environmental protection. And we are dealing here with highly special circumstances because of Alaska's small population and its undisturbed natural character. I feel very heavily the responsibility of being the decision-maker on this matter, and I assure you that I fully recognize the seriousness of the issues. We can take lightly neither the risk of damage to the Alaskan environment, nor the value to the Nation as a whole of the energy resources which may be found there.

The first question we have faced is whether the sale of leases in the Gulf of Alaska should be held now or should be delayed for further study and preparation.

We believe that our information on geologic hazards is already sufficient for holding the sale; the U.S. Geological Survey advises me that it has completed analysis of both public and proprietary geophysical data on such hazards, and is professionally satisfied that it now has sufficient knowledge to make recommendations on tracts which should or should not be included. Moreover, in the course of the last few weeks, working in consultation with the Environmental Protection Agency, we have progressed substantially in our drafting of operating orders for the Gulf of Alaska, and we will shortly issue in final form those orders which affect exploratory activity undertaken immediately after leasing.

On the other hand, I must substantially agree with your estimates of the length of the delay that would be necessary to improve significantly our knowledge and readiness in other areas. It will be several years before further biological and oceanographic studies will yield most of their results; and it may be that long or longer before the State of Alaska will accomplish the major legislative and planning steps which it would prefer to have complete before leasing.



It is my considered judgment, based on all these factors, that delays of such length in the lease sale would not gain us enough to be worth the cost in postponement of development of the resources. I am convinced that we already know what the major hazards are in oil and gas development of the Gulf of Alaska; further studies will refine that knowledge, but they are unlikely to change it fundamentally. I am further convinced that the operating orders, safety requirements, and lease stipulations developed by the Bureau of Land Management and the U.S. Geological Survey will reduce those hazards to levels which are acceptable.

The safety record of the OCS leasing program is an outstanding one, and our best judgment is that while environmental damage in some degree will occur, that damage will be largely temporary, sustainable, and worth risking in view of the prospect of adding substantially to our domestic energy supplies.

As you know, this is a lease sale for which first plans were actually laid in the late 1960's, and it is an area which has long been generally felt to hold higher promise than almost any other for significant new domestic energy. Our intentions to lease in the Gulf of Alaska have long been known, and the time for preparation there has been substantial.

Accordingly, I have decided that on balance it is in the National interest to move ahead with the lease sale, and I have directed that it be held as soon as our preparations are complete. This is not a decision I have reached lightly, but based on the balance of benefits and risks, I am convinced it is correct.

Size of the Sale

Deciding which tracts to include and exclude from the sale has required a similar balancing of benefits and risks, and a no less difficult one. As you know from your staff's extensive review, we have put a great deal of effort into careful analysis of the risks involved in development of different groups of tracts in the proposed sale area. In the end, of course, the matter of tract selection is judgmental, and no two people may totally agree on those tracts for which the expected value of the resource is great enough, and the risk to the environment small enough, to warrant leasing. My staff developed some fifteen different sets of tract choices, in addition to the suggestion made by EPA and endorsed by you, and I personally have spent many hours studying and hearing debate about all of them.

I have concluded that it would not be in the public interest at this time to lease all of the 1.8 million acres in the originally proposed sale, and I have directed that approximately 40 percent of the proposed acreage be eliminated:

- o All tracts west of Kayak Island will be eliminated except a group of sixteen along the northern tiers of the group originally proposed. Our studies indicate that these sixteen are both promising for oil and gas discovery and environmentally less risky than other tracts in that area, because of prevailing wind and current patterns.
- o A group of tracts will be eliminated near the southeast corner of Kayak Island, in order to reduce the risk of impacts near both Middleton Island and the Copper River Delta.
- o Ten tracts will be eliminated in the southeast region of the sale area which have been identified as important commercial fishery spawning grounds.
- o Ten tracts will be eliminated which the U.S. Geological Survey advises may not be capable of safe development because of geologic hazards, and for similar reasons a number of other tracts will be offered under special stipulations as to drilling and platform placement.

These tract eliminations reduce the proposed sale from 1.8 to some 1.1 million acres. In this matter I have been mindful of your views on tracts which should be offered. My decision, of course, calls for a larger sale than you have recommended. I urge you to consider that by far the most risky tracts have been removed, that the remaining overall probability of damaging accidents is low, and that the potential value to the Nation of discoveries in this area is very high. If we are to make sizeable discoveries, we must make sizeable acreage available for exploration. Unwarranted risks should not be taken, and in my judgment the tracts I have included in the offering can all be developed with a favorable balance of benefits to risks. I hope you will be understanding of my decision on this matter.

Other Sale Preparations

You recommended that U.S. Geological Survey's operating orders, especially 2, 7 and 8, be issued in final form before the sale date, and both you and EPA suggested a number of modifications in them. Let me say that having this matter called to our attention has been constructive and helpful; I am satisfied that this part of our preparations has benefitted a great deal from your review. We are now prepared to issue orders 1, 2, 3, 4, 5, 7 and 12 in final form, incorporating many of your suggestions. In particular, in the interest of drilling safety, we will not permit use of drilling rigs other than semi-submersibles except by express decision of the Director of the U.S. Geological Survey. Order 8 will be published

finally as soon as possible after the sale, when our studies of design criteria for production platforms are more complete. We will also publish in the Notice of Sale a statement calling attention to our plans to revise order 8 and others not yet final, to initiate a system of third-party verification for structures, and to impose requirements sufficient for safety in light of the special wind, wave, current and seismic conditions of the Gulf of Alaska. In making these further revisions, we intend to consult both your staff and that of EPA.

In accordance with your recommendations, our plans call for continuation of the present program of environmental studies in the Northeast Gulf of Alaska, and for holding no further lease sales in this immediate area for at least two years, so that maximum advantage can be gained from results of the studies now under way.

Your January 23 letter contained several recommendations on improving coordination among Federal and State agencies in the conduct of the Alaskan OCS leasing program. It is my general intention to follow up on those suggestions, and find what improvements can be made. As you know, in recent months we have taken major steps to enhance coordination with other agencies, Federal and State, which have an interest in the leasing program. I am directing that my staff review those coordinative mechanisms and report to me on how they can be strengthened. It may or may not be advisable to adopt the particular suggestions you have made, but your ideas are positive and constructive ones, and we will give them further careful consideration.

In light of the importance to the State of Alaska of future proposed OCS lease sales, and the parallel importance to the Nation of the potential development of Federal resources off Alaska's shores, at your suggestion I am calling for a review, in consultation with the State, of the entire future OCS schedule for Alaska. My hope is that such a review will bring us better understanding of our mutual concerns, and a better matching of Alaska's interests to the interest of the Nation in rapid exploration of the OCS. I am writing Governor Hammond today to request his assistance in this review.

Further, I have decided to adopt a suggestion made by EPA to require that lessees in the Northeast Gulf of Alaska, in a supplement to their exploratory plans, provide information about their projected onshore activities which may be helpful to State and local jurisdictions in preparing for the onshore impacts of OCS leasing. We already require such information at the development stage, as you know, and in most areas the onshore impacts of exploration will not be significant enough to warrant requiring it there too. But in this case, effects are apt to focus on a few very small communities. Whatever advance warning these communities can be given will be helpful.

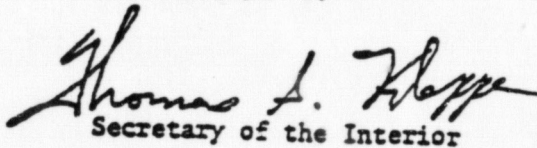
2556

The review of our plans for this proposed lease sale which Russ Train initiated on December 18 has now lasted for two months. It has required intensive work by you, your staff, and the staffs of EPA, the State of Alaska, and Interior. I believe we all have learned a great deal from it. On our part I have no hesitation in saying that you called important matters to our attention which required improvement; and on the other side I believe I am correct in observing that individuals involved from outside Interior have a higher regard now for our state of readiness than when the review process began.

I would like particularly to comment on the high standard of objectivity, intelligence and fairness your staff and that of EPA have maintained throughout this process. They have been properly insistent, but at all times they have also been constructive. We have profited from their efforts.

I know, Russ, that the decisions I have made differ from your recommendations. Nevertheless, I hope you will support them. They incorporate many of your ideas, and they represent my best judgment of the public interest, in the light of my responsibility for balancing enhancement of the Nation's energy supplies with protection of the environment. I of course stand ready to discuss these questions with you, and I know I can count on your further constructive assistance.

Sincerely yours,


Secretary of the Interior

Honorable Russell W. Peterson
Chairman
Council on Environmental Quality
722 Jackson Place, N. W.
Washington, D. C. 20006

UNITED STATES
DEPARTMENT OF THE INTERIOR

2557

FINAL
ENVIRONMENTAL STATEMENT

VOLUME 1 OF 3

PROPOSED
INCREASE IN OIL AND GAS LEASING
ON THE OUTER CONTINENTAL SHELF

FES 75



Prepared by the
BUREAU OF LAND MANAGEMENT

Earl R. Becklund
Director

BEST COPY AVAILABLE

From the safety standpoint, completion and workover operations must be conducted carefully, and it is their critical nature that, in all likelihood, makes these operations safer than they otherwise might be. Operators of swabbing and wire-line units are well aware of the hazardous nature of their work and are extremely cautious. Despite the potential hazard, safety records during wire-line and swabbing unit work are excellent.

d. Transportation of Produced Oil and Gas

Oil produced on the OCS can be moved ashore either by a tank vessel (barge or ship) or pipeline; gas, of course, can only be sent ashore by pipeline. As of 1971 only 3-1/2 percent of all OCS crude oil production was barged ashore; the remainder all came ashore in pipelines.

(1) Barges and Tankers

Tank barges are flat-bottomed vessels that may be self-propelled, towed or pushed. If they are towed or pushed, a sea-going tug is used as the power source. Tugs used for this purpose vary in size from 65 to more than 150 feet in length, and are powered by 350 hp to 4500 hp diesel engines. Although non-self propelled tank barges come in all sizes, three are most popular;

- 1000 ton capacity (7200 bbl.), 175 feet long, 26 foot beam, 9 foot draft.
- 1500 ton capacity (10,800 bbl.), 190 feet long, 35 foot beam, 9 foot draft.
- 3000 ton capacity (21,600 bbl.), 290 feet long, 50 foot beam, 9 foot draft.

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One tugboat of 4500 hp is easily capable of pushing ten of the 3000 ton barges that are lashed together. Some barges are provided with a notch in the stern into which the tug may be fitted and secured; others are towed by being lashed to the port and starboard sides of the tug.

Self-propelled barges that may be used offshore have capacities ranging from 20,000 to 25,000 bbl. A 20,000 bbl. barge averages 200 feet in length, 50 feet in width and draws 9 feet of water; 25,000 bbl. barges are all relatively new, are only slightly longer (236 ft.) than their predecessors, but are the same width and draft. Larger 30,000 bbl. barges are under construction. All self-propelled barges and tankers must be inspected and certified by the United States Coast Guard. Power is provided by two 1000-1500 hp diesel inboard engines, each connected to a powerful screw which moves the barge at an average open water speed of 10 knots.

There are three basic barge designs: 1) single skin (hull), 2) double skin, and 3) barges having independent cylindrical tanks. Single skin tank barges have both bow and stern compartments that are separated from the midship by collision bulkheads. The entire midship shell of the vessel constitutes the cargo tank with structural framing inside. Double skin barges have an inner and an outer shell with the inner shell forming the cargo tank. This

double skin structure provides added protection in case of collision, grounding, or some other mishap. Barges with independent cylindrical tanks are used for transporting liquids under pressure or where pressure is to be used to off-load the cargo; these will not be used for transportation of crude oil. In any case, barges usually do not have compartmentalized storage tanks.

The transfer of petroleum either into, or out of, a barge is a relatively simple operation. The vessel is docked either at an offshore platform or shore-based offloading facility usually with the aid of either an active rudder or a bow-thruster. Docking can be accomplished with relative ease in seas up to 5 feet. Once secured, hoses are connected to a manifold located on either side of the barge. These hoses must be equipped with a "quick-disconnect" apparatus in order to prevent a back flow from the hose from discharging into the sea. The coupler, because it may contain up to one-half gallon of oil, must have drip pans placed beneath it in order to catch any oil before it could spill into the water. The U.S. Coast Guard requires that a certified tankerman be present and on duty at the manifold during any oil transfer operations. After loading, or offloading, is completed, the transfer hose is drained dry by back flowing or draining the crude to the platform. The couple is then broken, and either a receptacle is placed over the end to catch the drippings or the hose is plugged directly.

Loading of crude oil is usually done by means of a gravity feed system either from platform storage tanks or directly from the well. Offloading of crude to shoreside facilities is accomplished by pumps located on the barge or shoreside. The average rate of loading or discharge is approximately 4000 bbl./hr.

A tanker is a self-propelled ocean-going vessel that is compartmentalized into tanks for transport of liquids. Tankers are much larger than tank barges, the smallest used in crude oil transport is about 10,000 deadweight tons (dwt) or 65-70,000 barrels capacity. For use on the OCS, the size tanker that could be used would be limited by the allowable draft at its unloading port. Barges and/or tankers may be used initially in the new areas until sufficient producing capacity is developed to justify a pipeline.

(2) Pipelines

Pipelines laid offshore are constructed and laid by several different methods, depending mainly on the size, location, intended use, and cost. One method, pipepulling, involves the use of barges and tugs to pull sections of welded pipe from an onshore launchway over the preselected right-of-way. These sections may either be dragged along the bottom or suspended by floats. There are at least three limitations to this system. First, an extensive section of shoreline, roughly perpendicular to the shore, must be available for the fabrication and launchway site. (Alternatively,

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UNITED STATES
DEPARTMENT OF THE INTERIOR

FINAL
ENVIRONMENTAL STATEMENT

VOLUME 2 OF 3

PROPOSED
INCREASE IN OIL AND GAS LEASING
ON THE OUTER CONTINENTAL SHELF

FES 75



Prepared by the
BUREAU OF LAND MANAGEMENT

Eustarklund
Director

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Construction of onshore facilities necessary to support and process OCS petroleum production will cause additional adverse environmental impacts. These impacts are discussed at length later in this chapter.

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3. Impacts Resulting from Accidents

The information discussed in this section was taken from previous OCS EIS analyses as well as numerous sections of the Council on Environmental Quality's OCS Oil and Gas - An Environmental Assessment, Report to the President (1974).

In any complex industrial operation involving heavy equipment, flammable materials, work at sea, large number of employees, and reliance on complex technology, it is inevitable that accidents will occur. Proper analysis of these accidents is a complex problem. The history of OCS petroleum development accidents provides a substantial data base for estimating the frequencies of future accidents. The Council on Environmental Quality contracted with ECO, Inc. and with the Massachusetts Institute of Technology to analyze the probability of offshore oil spills. Statistical analysis of oil spills is difficult because of the following characteristics of oil spills.

- The size range of individual spills is extremely large, from a fraction of a barrel to over 150,000 barrels.

- Most oil spills are small; in 1972, 96 percent were less than 24 barrels (1,000 gallons) and 85 percent was less than 2.4 barrels (100 gallons).
- A few very large spills account for most of the oil spilled, e.g. in 1970 and 1972, three spills each year accounted for two-thirds of all oil spilled in the United States in those years.

These facts are highlighted to point out that estimates of the average amount spilled are almost meaningless. The amount spilled from any source can vary by a factor of 1 million, and single spills like the Santa Barbara spill can distort the size distribution of spill magnitudes. Further, as shown in Table 108, annual fluctuation in spill volumes are quite large. There are at least two different ways of using oil spill statistics to assess the probable number and magnitude of oil spills which could result from the proposed acceleration of OCS petroleum leasing. First, the historical spill rates for each type of accident are described. This is the procedure followed in the majority of site-specific OCS EIS's. Then the probabilities of oil spills will then be discussed using the analysis done by the Massachusetts Institute of Technology for CEQ.

a. Natural Gas Leaks Associated with Blowouts

Information furnished by the Geological Survey for the period 1956 to 1973 lists 38 gas leaks associated with well

TABLE 108

OIL SPILL STATISTICS
(Barrels)

Type of Spill	1971	1972
Petroleum Industry-related Spill		
Terminals		
Number	1,475	1,632
Volume	125,800	54,700
Ships (offshore)		
Number	22	22
Volume	400	51,600
Offshore Production Facilities		
Number	2,452	2,252
Volume	15,600	5,700
Onshore Pipeline		
Number	74	162
Volume	8,700	29,300
Total		
Number	4,023	4,078
Volume	150,500	141,300
All Spills		
Number	7,461	8,287
Volume	205,000	518,000

Source: The Massachusetts Institute of Technology Department of Ocean Engineering, 1974. "Analysis of Oil Spill Statistics," prepared for the Council on Environmental Quality using U.S. Coast Guard data. (OCS Oil & Gas - An Environmental Assessment, Report to the President, CEQ, 1974).

blowouts during OCS petroleum development operations in the Gulf of Mexico. No gas leaks have been reported from the California OCS. Eleven of these incidents in the Gulf of Mexico involved fires and five were associated with oil or condensate spills. The duration of these blowouts ranged from two hours to over seven months. No estimates of the amount of gas lost have been made. Degradation of air quality is the primary environmental impact of gas leaks with or without fires. Several gas leak incidents also resulted in injury and death of members of the OCS platform crew, and damage or loss of valuable equipment.

b. Oil Spills Greater than 50 Barrels in Size

Data supplied by the Geological Survey for the period 1964-1974 (includes only first quarter of 1974), list 45 oil spill incidents of 50 barrels or more of oil and condensate resulting from Federal OCS oil and gas operations. Most occurred in the Gulf of Mexico. Only one of these incidents occurred in the California OCS operations--the blowout on Platform A in the Santa Barbara Channel. A detailed discussion of the Santa Barbara incident is presented in section III.D.2.

The estimated total volume of oil and condensate spilled during this 1964-1974 period is slightly more than 300,000 bbl. (12.6 million gallons). A distribution of the 44 Gulf of Mexico incidents as to type of accident and amount spilled is presented

in Figure 83 . The total production of oil and condensate from Federal OCS operations during the 1964-1974 period was approximately 2.9 billion barrels. Thus, the volume spilled compared with the volume produced results in an overall throughput spill rate of approximately .01035 percent. In the following discussion of oil spills by type of accident, this history of 45 OCS accidents will be used to provide an estimate of the expected throughput spill rates for each type of accident.

(1) Pipeline Accidents

During OCS operations, more oil has been spilled from pipeline accidents than from all other types of OCS petroleum production accidents. The largest OCS oil spilled occurred in October, 1967 when a vessel underway during a storm dragged its anchor, which was inadvertently left out, across a pipeline. The snagged pipeline severed and the resulting spill went undetected for nearly two weeks, releasing over 160,000 barrels of oil into the ocean about 20 miles west of the mouth of Southwest Pass, Mississippi River Delta, Louisiana. In March of 1968, another anchor dragging incident resulted in a 6,000 barrel spill. In February of 1969, a pipeline leak of undetermined cause released over 6,500 barrels into the sea.

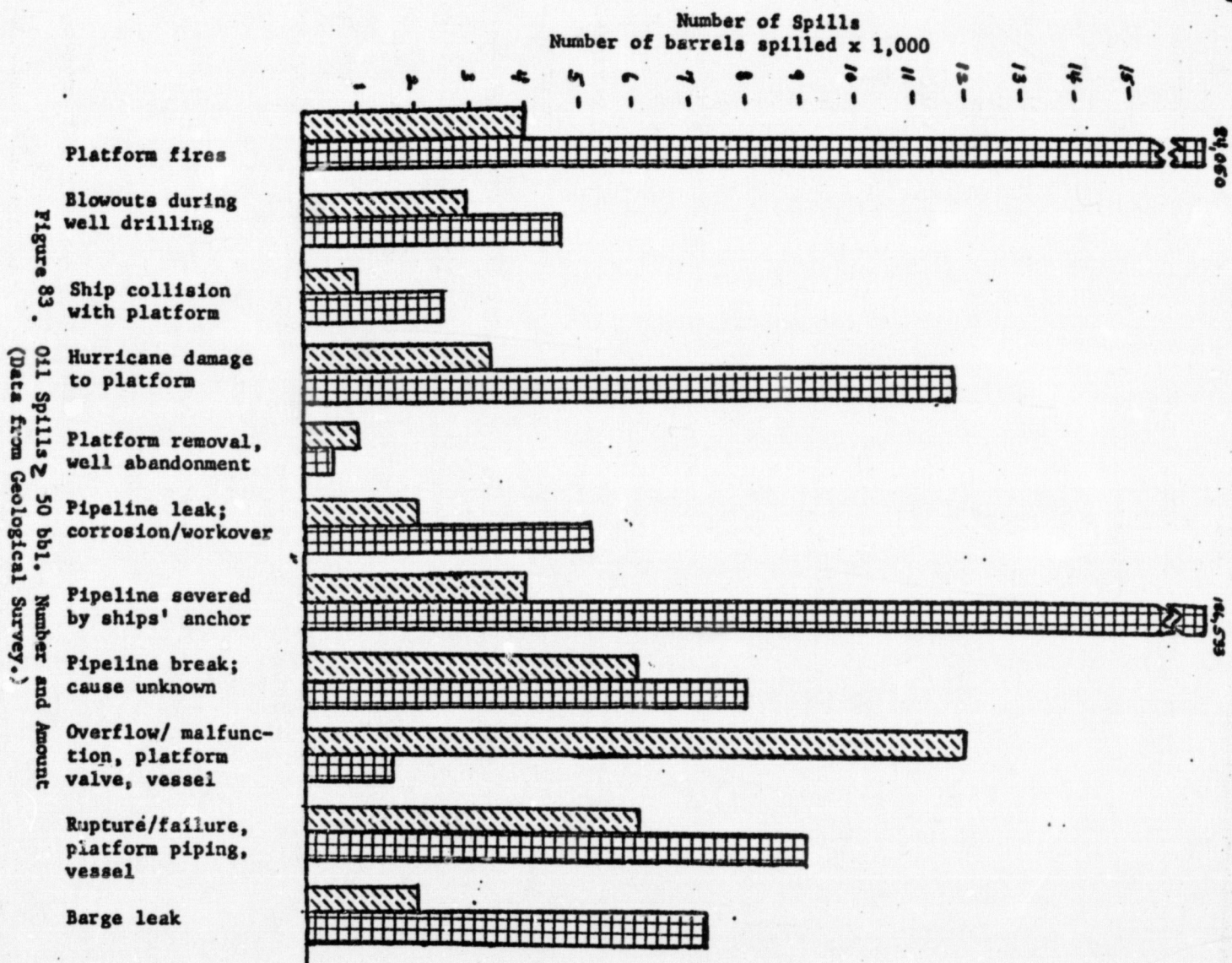
Starting in 1969, several actions were undertaken to reduce the chances of such accidents and to reduce the volume of these spills. Burial of all new common carrier pipelines with a minimum cover of

Amount of oil spilled



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Number of spills



three feet (10 feet in shipping fairways and anchorage areas) was required by BLM for right-of-way permits in water depths of less than 200 feet. The water depth requirement for pipeline burial may be increased to 250 feet for the Southern California OCS sale. In water depths of less than 200 feet, only the lines in the gathering system between adjacent platforms of a particular oil or gas field may remain unburied. Permits to construct these gathering lines are granted by the Geological Survey and the decision on whether to require burial is made on a case-by-case basis. These administrative actions have substantially reduced the risks of future pipeline ruptures due to anchor dragging.

Additional safeguarding of OCS pipelines and mitigation of accidental spills is provided by regulations promulgated by the Office of Pipeline Safety (OPS), of the Department of Transportation. Petroleum pipelines in offshore areas are required to be coated with tightly banded materials impervious to moisture, followed in many cases by a layer of dense concrete for mechanical and corrosion protection (49 CFR Parts 192 and 195). To protect against electrolytic corrosion, impressed currents of sacrificial anodes are required. Regulations by OPS also mandate use of a continuous line pressure monitoring with some type of built-in alarm or automatic shut-down system. The OPS regulations requiring protection devices and pressure monitoring systems, coupled with regular inspection of the

pipeline route for leaks and other irregularities, should also substantially reduce the risk of pipeline oil spills.

Other features used by industry serve to further mitigate against accidents: continuous metering systems, automatic high pressure shut-downs, and remotely controlled mainline block valves that can isolate sections of the line. The latest pipe-laying and monitoring techniques, combined with modern materials and equipment, will further help to insure that the pipelines used in the various OCS areas will function at an acceptably high level of reliability.

Prior to institution of the new pipeline burial requirements, the spillage rate from pipeline accidents was .00624 percent of total production. With the new regulations, this spillage rate has been substantially reduced to .0017 percent of total production in the period since 1970. Although the new regulations and improved industry practices have brought the spillage rate down, the problem of pipeline spills from anchor dragging has not been completely removed. As a part of the pipeline management program, the costs and benefits of extending pipeline burial systems will be investigated.

Caution should be inserted at this point. The improved performance of pipelines now in existence may not continue. Industry spokesmen

have estimated that 48 percent of all pipeline leaks occur in lines that have been in use for 15 years or more. In established offshore petroleum fields where older pipelines are present, corrosion may be in an advanced state. Such pipelines may be poorly buried, if at all, and all of the above mentioned safety and control features may not apply. If serious spillage should occur from some of these older pipelines, the statistical improvement in pipeline performance could be reversed. However, in each future OCS lease sale, all of the safety and control requirements discussed above will be enforced. Therefore, it may be expected that these pipelines should function adequately, since they will be new lines.

(2) Oil and/or Gas Well Blowouts During Drilling

Data from the Geological Survey lists a total of 44 blowouts in Federal OCS petroleum operations during the 1964-1974 period. Only 17 of these blowouts resulted in oil spills of 50 barrels or more. The total amount of oil and condensate spilled was approximately 73,000 barrels. Examination of OCS statistics indicate one blowout per 2,860 wells drilled (or .035 percent of wells drilled blew out), spilling an average of 2,100 barrels of oil and condensate per blowout.

The Santa Barbara oil spill provides an example of a blowout during drilling.

Santa Barbara Spill

On January 29, 1969, a blowout occurred below Platform A about six miles southeast of Santa Barbara, California. Thousands of gallons of oil spewed into the Santa Barbara Channel, as men worked feverishly to regain well control. This blowout and spill occurred through a pre-existing fault in the ocean floor adjacent to the well. The apparent cause was accidental injection of high pressure gas from a deep reservoir into the shallow reservoir sands. Pressure built up in the shallow reservoir sands until the overlying rock layer ruptured. This rupture formed a fissure zone through which the oil moved up to the seabottom and escaped into the overlying waters (Reinhart, 1970). The blowout continued for 10 days, until the well was choked with cement on February 7, 1969. The reprieve was only momentary and spillage began anew a few days later. Some seepage continues to this day.

The Geological Survey estimated that the initial spillage from the Santa Barbara blowout totaled 420,000 gallons (10,000 barrels). Other estimates of the initial spillage range from 2,940,000 gallons to 29,400,000 gallons (70,000 to 700,000 barrels).^{1/} An additional seepage of 10,325 barrels occurred between February 7, 1969 and December 31, 1972. During 1973, this seepage continued at a rate of 1,825 barrels per year.

^{1/} Testimony of Dr. Carl H. Oppenheimer, OCS Public Hearing of August 23, 1972, New Orleans, Louisiana.

(3) Oil Spills Resulting From Explosions and Fires

Fires have always been a major hazard in the petroleum industry. OCS operations are no exception. Most fires are ignited by arcing electrical equipment and overheated mechanical devices. More rarely, lightning or static electricity is the cause of ignition. Sometimes, platform fires result from accidental ignition of stored fuel, solvents, or heat exchanger fluids. If caught soon enough, these small fires are usually controllable. If a storage tank or well catches on fire, the resulting inferno can cause major structural damage. Adjacent producing wells may have their piping severed and thereby contribute additional fuel to the fire. The majority of fires are quickly extinguished with little or no damage. Uncontrollable fires causing major structural damage usually involve numerous wells in the fire and all too often result in multiple fatalities.

The Geological Survey has reported 113 explosions and fires in the 1964-1974 period of Federal OCS activities. Most of these fires were extinguished before serious damage and pollution occurred. Only six of these accidents resulted in oil spills. However, the volume spilled in two of these incidents was very large, 30,500 barrels from one and 53,000 from the other. The total volume spilled from all explosions and fires is approximately 85,000 barrels. Perhaps of greater significance is the injury of 120 men and the death of an additional 59.

Due to the serious threat of injury and death, industry is typically very cautious about OCS explosions and fires. However, due to the history of fire-caused massive oil spills, OCS orders were amended to require extra safety precautions to reduce the potential for future fire related oil spills. To eliminate blowouts due to malfunctioning velocity-actuated downhole safety devices, OCS Order No. 5 requires surface actuated safety devices. If all wells are successfully closed during fires and explosions, the size of future fire-caused oil spills should be limited to the volume of flammables stored on the platforms when the fire started. Since 1971, explosion and fire accidents have not resulted in more than minimal oil spills.

(4) Oil Spills Caused by Severe Storms - Hurricanes

In the history of Federal OCS oil and gas activities, there has been only one severe storm which caused significant oil spillage. On October 3, 1964, a hurricane passed over the waters off central Louisiana destroying three OCS platforms. The total volume of oil spilled in this hurricane was approximately 12,000 barrels. All of this spilled oil was from tanks used to store produced oil prior to trans-shipment by barge.

Since 1964, three major hurricanes have hit the extensive offshore petroleum production areas off Louisiana. While causing financial damage to the offshore industry, they have not resulted in major

pollution incidents from operations in Federal waters. When the Weather Service advises that a hurricane or serious tropical storm is imminent, all oil and gas facilities in or adjacent to the path of the storm are evacuated. Before evacuation, all surface equipment and wellhead controls are shut-in. In addition, blank tubing plugs are set in as many wells as possible to further reduce the possibility of pollution in the event the well is damaged.

The efficiency of these safety precautions was amply demonstrated during Hurricane Camille. On August 17, 1969, Camille passed along the eastern flank of the Mississippi Delta of Louisiana and into the Mississippi Gulf Coast. ^{1/} Camille's topwinds were estimated at 201.5 miles per hour and the storm surge raised sea level 22.6 feet above normal at Pass Christian, Mississippi. During Camille's onslaught, one production platform was destroyed and two were damaged, two drilling rigs were destroyed, and three were damaged. No significant oil spillage occurred.

The severity of storms occurring in the various OCS areas are substantially different from those encountered either in the Gulf of Mexico or off California. With only one incident on record, no generalization should be made concerning the maximum spillage which future severe storms may cause. The issue of storm-related hazards of operating in the various OCS areas is discussed in section III C.

^{1/} Corps of Engineers, Report on Hurricane Camille. Report No. 1338, 1970, U.S. Army Engineers District, New Orleans, Louisiana.

(5) Oil Spills Caused by Ships Colliding with Platforms

Commercial vessels can collide with OCS platforms, typically causing substantial damage to both the vessel and the platform. This section deals only with the oil spilled from platforms. The oil spilled from the vessels colliding with the platforms is dealt with in the next subsection. Accident records indicate only one instance of a significant oil spill from a platform caused by ship collision. In April, 1964, a freighter off central Louisiana struck and damaged a platform, resulting in a fire and loss of 2,560 barrels of oil into the sea. A history of one accident does not provide sufficient information to allow generalization about the magnitude or frequency of future collision related oil spills.

(6) Tanker and Tank Barge Accidents and Operations

Accidental oil spills from tankers and tank barges, as well as oil discharged during normal operations, are probably the largest sources of oil spills in the U.S. There are a wide variety of data sources for tanker accidents world-wide and estimates of tanker and tank barge spill rates vary widely. For example, the Bureau of Land Management has often used the 1971 data for world wide water-borne petroleum transports carried by the U.S. tanker fleet. This data indicates a spill rate of .08 percent of each cargo. Porricelli (1969) states that .03 percent of each cargo

of U.S. tank barges is spilled into the marine environment each year as a result of mishaps and operations. Finally, the Massachusetts Institute of Technology, using a more complex data base, computed a ratio of the mean spill rate to the total volume of oil handled of .016 percent. This diversity of oil spill rates for tankers obviously makes it more difficult to state the expected spill rate associated with tanker and tank barge operations.

No matter which of the above estimates of tanker oil spill rates is used, the result is the same. Transportation of petroleum in tankers and tank barges is hazardous. In fact, all of the above tanker spill rates are higher than the total of all other OCS spill rates. This high oil spill hazard of tanker and tank barge transportation of petroleum is a very important factor in distinguishing the relative oil spill hazards of the various OCS areas. If the OCS petroleum production can be piped to shore, the oil spill hazard is substantially less than the oil spill hazard when tankers and barges are used. Further, if the oil and gas production of an area has to be transported by tankers out of that area for consumption in another area, once again the operation is exposed to the higher relative hazards of tanker transportation. An area by area assessment of the expected means of transporting OCS petroleum production for each area is presented in Section III.C.

It is difficult to assess the total amount of petroleum that will be spilled into the marine environment as a result of the daily operation of U.S. flag tankers and tank barges. Although there are estimates of the total amount of pollution resulting from cargo handling, tank barge leaks, and cleaning/bunkering/ballasting/bilge pumping, (Charter, et al., 1973 and Porricelli, et al., 1971) there is no breakdown according to registry. It should be noted, however, that U.S. Coast Guard regulations and standards are among the most stringent and rigidly enforced in the world.

Throughput spill rates are not the only available method for assessment of the oil spill hazards of tanker transportation of petroleum. The Massachusetts Institute of Technology performed an extensive analysis of oil spill statistics for the Council on Environmental Quality (Report No. MITSG 74-20, April 1974). Their analysis indicated that average spill rates were almost without meaning. Therefore, they concentrated their efforts on estimating the probability of spills larger than 1,000 barrels. Analysis of tanker spill statistics indicated that approximately 98 percent of all oil spilled from vessels is from incidents over 1,000 barrels. Most large tanker spills occur nearshore and are caused by groundings, ramming (the vessel hits a fixed structure), or collisions. Groundings and ramming occur nearshore and collision frequency depends on traffic density, which is highest nearshore.

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M.I.T. expressed oil spill hazards as estimates of the probability of spills larger than 1,000 barrels. As the size of the petroleum field increases, so do the number of expected spills and the overall probability that a spill will occur. M.I.T. classified oil and gas discoveries as small finds, i.e. 500 million barrels of oil in place; medium finds, i.e. 2 billion barrels of oil in place; and large finds, i.e. 10 billion barrels in place. Using a complex worldwide data base of past tanker oil spills, M.I.T. estimated that the probability of one tanker spill over 1,000 barrels during the life of a small field was approximately 27 percent. During the life of a medium sized field, there is approximately an 85 percent probability of one such spill. For a large find, this probability is nearly 100 percent. M.I.T. also estimated the expected number of tanker spills over 1,000 barrels as well as the expected volume of spills over the life of each field size. The results were: small find 0.40 spills, 19,900 barrels; medium find 1.9 spills, 92,400 barrels; large find 6.9 spills, 335,700 barrels. The estimates of volume spilled dramatically state the oil spill hazards of tanker transportation.

(7) Other Spills of 50 Barrels or More

This category is a combination of spills over 50 barrels which had causes other than those discussed above. Accident records indicate a total of 15 such spills through 1973. Total discharge from

these spills amounted to approximately 9,200 barrels. Twelve of these spills were attributed to overflow, malfunction, rupture or failure of platform piping valves or vessels.

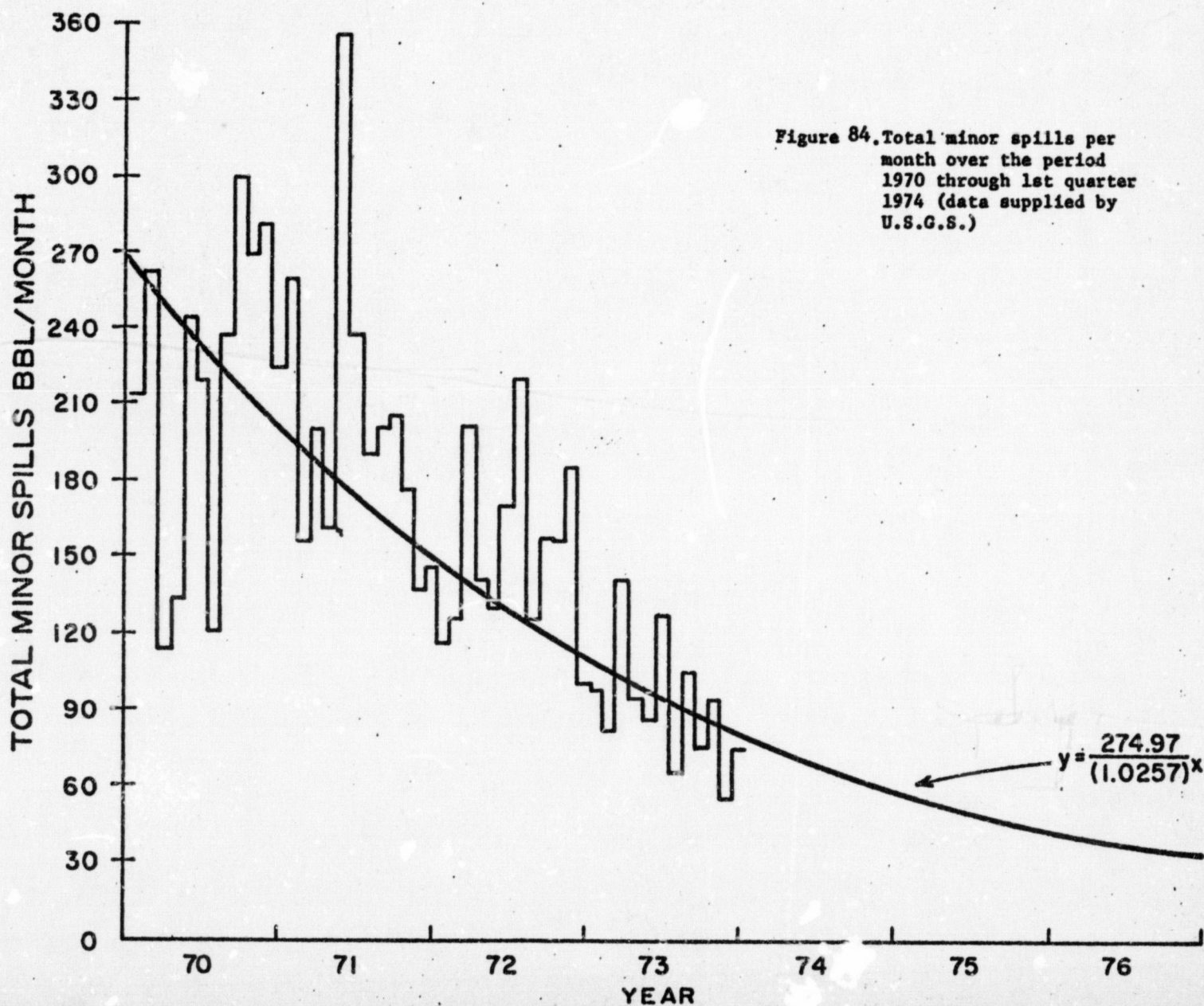
One spill occurred during abandonment and platform removal. In this operation a well broke and spilled 500 barrels of oil. To help prevent recurrence of this type of spill, OCS Operating Order No. 3 requires that a redundant series of bridging devices, weighted muds, and cement plugs be placed in any well or drill hole prior to abandonment. Well and drill hole abandonments performed in this manner should provide an ample margin of protection to prevent future oil spills from abandoned wells or drill holes.

Two similar incidents, occurring in July, 1971 and January, 1973, caused spills totalling 7,100 barrels. Both of these spills were caused by damage to oil storage barges.

(8) Minor Spills

Starting in 1970, the Geological Survey required reporting of oil spills less than 50 barrels in size. Since then some 5,000 such minor spills have been reported. Table 109 lists the annual totals of minor spills by number, volume and source. Even though the number of minor spills each year has increased slightly during the 1970-1973 period, the total volume spilled has decreased substantially. Figure 84 shows the decreasing trend in volume of oil

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spilled per month during the 1970-1973 period. During this same period, the total OCS petroleum varied by less than 13 percent, whereas the volume of minor spills decreased by approximately 60 percent. This substantial decrease in the volume of oil spilled in minor spills probably indicates an improvement in industry's performance in cleaning up its routine operations and thereby reducing the amount of chronic spillage.

Table 109 Minor Oil Spills

<u>Year</u>	<u>Total Number Reported</u>	<u>Number by Source</u>		<u>Total Volume Barrels</u>
		<u>Drilling</u>	<u>Prod. & Trans.</u>	
1970	1,200	4	1,196	2,597
1971	1,250	13	1,237	2,414
1972	1,158	13	1,145	1,812
1973	1,392	10	1,382	1,857
<u>Total</u>	<u>5,000</u>	<u>40</u>	<u>4,960</u>	<u>8,680</u>

Note: Total OCS petroleum production during the 1970-1973 period was 1,488,242,300 barrels. Therefore, the minor spills spillage rate is 0.000583 percent.

(9) Summary of Throughput Spillage Rates

Each of the eight preceding subsections dealing with oil spills from OCS operations identified the volume of oil spilled for each class of accidents. With the exception of oil spills caused by blowouts, the volume spilled can be expressed as a throughput spillage rate, i.e., total volume spilled divided by total volume produced. Spill rates for blowouts are better expressed as blowouts per well

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drilled. This section brings all of these spillage rate estimates together. The reader is cautioned on three points.

First, as explained in detail in the preceding discussion, the quality of the data varies among the causes of accidents. For several accident categories, there are not sufficient data to allow extrapolations about expected future spill rates.

Second, it must be emphasized again that to date OCS oil and gas operations have occurred in only the Gulf of Mexico and off Southern California. The natural environmental conditions, i.e. severe storms, earthquakes, tsunamis and bottom types encountered in the frontier areas of the OCS will differ substantially from those experienced to date. Therefore, this historical accident data provides a questionable basis for predicting accident frequencies in areas such as the Gulf of Alaska or Georges Bank. This problem is discussed at length in Section III.C.

Third, as already noted, the statistical validity of throughput, spill rates is questionable. The amount spilled from the same type of accidents can vary by a factor of 10,000 or more, e.g. the largest pipeline accident spilled over 160,000 barrels of oil and the smallest significant pipeline spill was less than 100 barrels. The

presence of a single large spill in the accident history can seriously distort the mean spill rate especially when changes in OCS Operating Orders have substantially reduced the chances of another large spill. These observations among others lead M.I.T. to a different approach for estimating the hazards of future oil spills. The M.I.T. analysis of oil spills is presented in Section III.B.4.

These caveats aside, the throughput spill rates are shown in Table 110.

Table 110

Throughput Spill Rates

<u>Accident Class</u>	<u>Spill Rate</u>
1. Pipeline accidents	.00170 percent <u>1/</u>
2. Blowouts	.00290 " <u>2/</u>
3. Explosions and Fires	.00290 "
4. Severe storms	.00041 "
5. Ship Collisions with Platforms	.00009 "
6. Tanker and Tank barge	.01600 " <u>3/</u>
7. Other Spills of 50 Barrels or More	.00032 "
8. Minor Spills	.00058 "
Total without tankers	.00890 "
Total with tankers and without pipelines	.02320 "
Total with both tankers and pipelines	.02490 "

1/ Pipeline spill rate since 1970. See Section III B.3 b) 1)

2/ Blowouts expressed as throughput spill rate. An alternative expression is .035 percent of wells drilled blowout with an average spill of 2,100 barrels per blowout.

3/ The M.I.T. estimate of tanker throughput spill rate.

Throughput spill rates are based on historical experience. Using throughput spill rates as a basis for forecasting oil spill rates in the frontier areas of the OCS would require the following assumptions:

- 1) That oil spill prevention efforts are equally successful as they have been in the Gulf of Mexico and the Santa Barbara Channel OCS area;
- 2) That the different environmental conditions of the frontier OCS areas represent an equal hazard to OCS operations as the conditions encountered to date; and
- 3) That the historical observations provide a sufficient data base to accurately estimate spill rates.

There are substantial factual reasons for doubting the validity of each of these assumptions.

OCS Operating Orders have been changed to abate certain key oil spill hazards and as a result of these efforts oil spill rates should go down. However, the operating environments of the

Explanation for Table 110 (cont')

various OCS frontier areas include natural environmental phenomena not experienced in U.S. OCS operations to date. Finally the historical data on OCS oil spills provides an insufficient basis for forecasting throughput spill rates. These caveats about the use of historical data should be kept in mind when these throughput spill rates are used in Table 111 as a basis for forecasting future spill rates.

These estimates of throughput spill rates provide a basis for computing one type of estimate of the expected volume of oil spills in each OCS area. To make these throughput spill estimates, two additional pieces of information are necessary. Obviously, estimates of the expected production are required for each area. The U.S. Geological Survey provided the likely production estimates shown in Table 106. With the information presently available, these estimates of expected production are highly speculative.

The second piece of additional information needed to compute throughput spill rates is identification of likely methods of transporting the petroleum production for each area. Once again this information was requested from the Geological Survey. Specifically, the Survey was asked to determine for each area: (1) Whether pipelines or tankers and barges would be used to transport OCS oil and gas production to shore; and (2) whether the OCS oil and gas production of an area would be exported for consumption in another area. The USGS response was quite general. Tankers will be used to transport OCS oil to shore from deep water drilling sites. In all other instances pipeline transportation to shore was assumed. Additionally the Geological Survey assumed that all Alaskan OCS petroleum production would be tankered out

for refining and consumption in another area. The Geological Survey did not base this response on elaborate or detailed studies of the likely transportation method for OCS petroleum production in each area.

Combining the information in Table 106 and 110 produces an estimate of the expected volume of oil spills for each area. The procedure is to use Table 110 to identify the total throughput spill rate appropriate for the expected transportation system for each area. Then by multiplication of this throughput spill rate by the expected production levels depicted in Table 106 the results presented in Table 111 are obtained.

The expected spillages shown in Table 111 are large. The basic reason for this is the very large expected production from the OCS areas. These estimates, being the product of the expected production and the appropriate total throughput spill rate, increase as the expected volume of oil and gas production increases. To place these estimated spill volumes in context, the expected magnitude of petroleum production for each area must be kept in mind. To date, the total of OCS petroleum production has been only 2.9 billion barrels. The proposal to accelerate OCS oil and gas ~~leaving~~ could result in production levels 6 to 30 times larger than the total of OCS production to date.

Table 111

ESTIMATES OF AVERAGE ANNUAL OIL SPILL VOLUMES BASED ON THROUGHPUT SPILL RATES
(Over the Life of the Field)

Areas	Average Annual Production (Million Barrels)		Throughput Spill Rate Percent (Table 109)	Average Annual Spillage (Barrels)	
	Mean	5%		Mean	5%
North Atlantic	45.00	71.43	.0089	4005	6357
Mid-Atlantic	72.00	131.42	.0089	6408	11,696
South Atlantic	20.00	43.33	.0089	1780	3856
MAFLA	50.00	77.14	.0089	4450	6865
MAFLA Deep	(25.00)	(43.33)	.0232	(5800)	(10,053)
Central Gulf & South Texas	126.67	160.00	.0089	11,273	14,240
DEEP	(36.00)	(54.29)	.0232	(9352)	(12,595)
So. California	44.00	60.00	.0089	3916	5340
DEEP	(48.00)	(82.86)	.0232	(11,136)	(19,224)
Santa Barbara	60.00	85.71	.0089	5340	7628
DEEP	(36.00)	(60.00)	.0232	(8352)	(13,920)
No. California	26.67	26.67	.0089	2374	2374
Washington-Oregon	13.33	23.33	.0089	1186	2076
Cook Inlet	48.00	68.57	.0249	11,952	17,074
Gulf of Alaska	60.00	134.29	.0249	14,940	33,438
Aleutian Shelf	6.67	8.00	.0249	1661	1992
Bristol Bay	35.00	68.57	.0249	8715	17,074
Bering Sea	88.00	175.00	.0249	21,912	43,575
Chukchi Sea	213.33	362.50	.0249	53,120	90,263
Beaufort Sea	110.00	190.00	.0249	27,390	47,310

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Explanation for Table 111

The explanation for Table 110 expressed the necessary caveats about the use of throughput spill rates in forecasting future OCS oil spills. Table 111 presents estimates of annual throughput spill volumes. These estimates are obtained by multiplying the USGS estimates of undiscovered recoverable resources by the throughput spill rate appropriate for each particular OCS area.

Inspection of the column headed Throughput Spill Rate (Percent) reveals that each of the OCS areas is assigned an appropriate total throughput spill rate. This was done by noting whether or not tanker or tank barges would be used to transport OCS petroleum production to shore. Additionally, it was necessary to identify whether the petroleum production of each OCS area would likely be consumed in that region or exported by tanker for consumption in another region. The following assumptions were used to specify whether pipelines only, tankers only, or pipelines and tankers would be used in transporting the OCS petroleum production of each area:

- (1) For all deepwater areas, i.e. 200 meters to 2500 meters, tankers will be necessary to transport the oil to shore;
- (2) All Alaskan OCS petroleum production will be pipelined to shore for storage then tankered out of Alaska for refining and consumption in other areas; and

EXPLANATION FOR TABLE 111 (cont')

(3) Oil production of all other OCS areas will be piped to shore and consumed in the adjacent coastal area.

The U.S. Geological Survey was the source of these assumptions. Because of the substantially higher throughput spill rates for tanker transportation as compared to pipeline transportation, these are very important assumptions. The potential for an error in these assumptions must be added to the other caveats, which were noted in the explanation for Tables 109 and 110 about the use of throughput spill rates and recoverable resource estimates as a basis for forecasting future OCS oil spill rates. When all of the assumptions necessary for the validity of throughput spill rates are considered it is highly doubtful that there is much if any meaning in these estimates. Certainly the absolute amounts of annual oil spilled should not be interpreted as having anywhere near the precision implied. This apparent numerical precision is an artifact produced when the two numbers are multiplied together. A far more reasonable interpretation of these throughput spill volumes is obtained by grouping the estimated volumes into categories such as high, moderately high, moderate, and low. The results of such a categorization are:

<u>High</u>	53,120 barrels/year Chukchi Sea
	27,390 barrels/year Beaufort Sea
	21,912 barrels/year Bering Sea
	19,697 barrels/year Central and Western Gulf of Mexico shallow and deep

Moderately High

15,148 barrels/year Southern California
shallow and deep
14,940 barrels/year Gulf of Alaska
13,764 barrels/year Santa Barbara
shallow and deep

Moderate

11,952 barrels/year Cook Inlet
10,300 barrels/year MAFLA shallow and deep
8,715 barrels/year Bristol Bay
6,408 barrels/year Mid-Atlantic
4,005 barrels/year North Atlantic

Low

2,374 barrels/year North & Central California
1,780 barrels/year South Atlantic
1,661 barrels/year Aleutian Shelf
1,186 barrels/year Washington & Oregon

These annual spillage rates are based on the Geological Survey best estimate (mean) of the expected oil production for each area.

It is important to note the assumption that all deep water production will be tankered to shore drastically increased the throughput spill volumes for the deepwater areas. This assumption could be wrong. If it is, the categorization would change.

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4. Probabilities of Oil Spills Larger Than 1,000 Barrels -
The MIT Analysis

Throughput spill rate computations represent one method of estimating the expected severity of future oil spills. An important alternative method was developed by ECO, Inc., and the Massachusetts Institute of Technology for the Council on Environmental Quality (1974).

MIT focused its analysis on the frequency and magnitudes of OCS oil spills with the intent of developing probability estimates for such events as: oil spills greater than 1,000 barrels in the life of a field, the time elapsed between spills larger than 1,000 barrels and the expected number of spills in the life of the field. The sophisticated statistical techniques utilized by MIT are beyond the purview of this discussion. However, the results of the MIT analysis are presented in this subsection. Sources of data used in their study were:

- Coast Guard Pollution Incident Report System
- ECO, Inc., data base on tanker casualties (1960-1972)
- Petroleum Systems Reliability Analysis Data base generated by Computer Sciences Corporation for the Environmental Protection Agency
- MIT data base on large spills
- A sample of 300 spills at single point moorings worldwide, principally from testimony at hearings before the House of Lords on a proposed Anglesey, England, terminal.

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Important characteristics of oil spill data include the following:

- Amounts spilled in accidents of similar cause can vary by at least a factor of 100,000.
- The presence of a few very large spills in the historical record can substantially distort the statistical distribution of spill magnitudes.
- The fluctuations from year to year are quite large.

All of these factors tend to make for meaningless estimates of average amounts of oil that might be spilled at particular steps in the development process.

a. Platforms and Pipelines

For a small oil field discovery there is about a 25 percent chance of one platform spill over 1,000 barrels; there is about a 70 percent chance of one platform spill for a medium field and for a larger field, the probability of at least one spill larger than 1,000 barrels is approximately 95 percent. The probability of pipeline spills follows the general pattern exhibited by platform spill probabilities.

Biologically, the time interval between large spills may be at least as important as the number of such spills. The probability of successive oil spills increases rapidly as the size of the field increases. Specifically, the expected time interval between large spills (over 1,000 barrels) for a small field is 4-5 years; the

corresponding time interval for a medium field is approximately 2 years; and for a large field, it is only one year.

b. Tankers

The material reported in this subsection was presented above in Section III.B.3.b.⑥. It is repeated here for convenience.

Analysis of tanker spill statistics indicates that if tankers are used to transport oil to shore, the probability of at least one oil spill over 1,000 barrels is about 27 percent during the life of a small find, about 85 percent for a medium find, and nearly 100 percent for a large find. The expected time interval between spills larger than 1,000 barrels is approximately 2.5 years for a small find, slightly over one year for a medium find, and slightly over one half a year for a large find.

c. Total Number and Volume of OCS Oil Spills

The total volume spilled over the life of a field can also be estimated using the MIT approach. First, the expected number of spills over 1,000 barrels is estimated for each field size. Then the expected volume spilled can be computed by multiplying the expected number of spills by the expected spill size for each class of accident. Table 112 depicts the results of these computations for small, medium, and large field sizes. Platforms have the lowest frequency and volume of spills, and tankers the highest. Once again,

TABLE 112

Oil Spilled Over the Life of a Field

	Number of Spills	Total volume (barrels)
Small Find		
Platform	0.28	7,200
Pipeline	0.31	13,900
Tanker	0.41	19,000
Medium Find		
Platform	1.3	33,300
Pipeline	1.4	62,900
Tanker	1.9	92,400
Large Find		
Platform	4.7	120,500
Pipeline	5.2	233,300
Tanker	6.9	335,700

Source: Massachusetts Institute of Technology, "Oil Spill Trajectory Studies for Atlantic Coast and Gulf of Alaska," Primary, Physical Impacts of Offshore Petroleum Developments, prepared for the Council on Environmental Quality under contract No. EQC330 (Cambridge: Massachusetts Institute of Technology, 1974), Report No. MITSG 74-20.

J. Alternative OCS Exploratory Programs

1. Description

a. Special Limited Leasing in Frontier Areas with Requirements for Prompt Unitized Exploration.

Tracts of flexible size and shape that correspond to geologic structures could be offered in frontier regions. Such leasing would encourage the full development of geologic structures as opposed to limiting development to tracts of 3x3 mi. blocks. Advantages would include the following: no other changes in regulations required, procedures are well established, large areas tend to reduce duplication of exploration effort, large size of tracts will encourage most profitable prospects to be drilled first, large tracts will promote efficient single-company ownership and operation of fields. Disadvantages include the following: most profitable fields are not always largest fields, dilutes total exploration effort by follow-up development drilling, bonus bids may be even larger and more counter-productive in terms of capital demand, and such a change would require an alteration in the law.

b. Leases for Exploration only - Develop Lease upon Discovery (If Leasing Scheduled for Area)

Exploratory oil and gas leases on the OCS except in the Gulf of Mexico and the Southern California Continental Borderland have

been suggested. The leases would be issued to the highest responsible qualified bidder by competitive bidding. The lease would be for a term of one year and would extend over a set number of acres. An exploratory oil and gas lease would not authorize the production of oil and gas from the leased area except for testing the scope and quantity of any oil and gas discovered. If oil and gas are discovered on the lease during the life of the lease, the company holding the lease shall, without competition or the payment of a bonus, be entitled to a preference right lease covering the discovery. The preference right lease would require a payment of royalty as well as a payment of a share of net profits which would be established by the Secretary of the Interior at the time of issuing the exploratory lease.

c. Federal Exploratory Drilling Program

The Federal Government could conduct its own drilling program on the frontier areas of the Outer Continental Shelf. Such an effort would have to be directed towards the most favorable geological structures since the Government does not presently have the capacity to study all the smaller structures. Even a limited effort by the Government, most likely the U.S. Geological Survey, would put a strain on personnel, procedures for contracting

and hiring, and general organizational structure. It would be necessary to immediately contract offshore rigs or else they will be unavailable, which might already be the case. A hostile reaction might be encountered from industry which could result in legal delays. Then of course, industry would also do its normal exploration and research resulting in a duplication of effort. About the only advantage that a Federal Exploratory Drilling Program would be the added knowledge the Government would receive, and perhaps could better evaluate the hydrocarbon resources to be leased.

d. Off Structure Stratigraphic Drilling

1. Federally Conducted

The Federal Government could conduct an off structure stratigraphic drilling program for the purpose of obtaining stratigraphic data. The intent would not be to discover hydrocarbons, but to learn more about the regional geology of the Outer Continental Shelf.

The basic idea of an off structure drilling program is good, but a Federally conducted program would not be practical under existing manpower and budget constraints.

2. Privately Conducted

There is an off structure stratigraphic drilling program presently being conducted privately with Government cooperation

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off the coast of Texas. This is the only area where such a program is taking place. Stratigraphic drilling will be included in the proposed U.S.G.S. permit system allowing early aquisition of geological and geophysical information. (See attachments)

E. Quality and Usefulness of EIS Preparation and Review

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As noted earlier, every effort should be made to design the OCS leasing program so that energy supply objectives are met with minimum environmental risk, and so that the most environmentally vulnerable areas will be protected from possible irreversible adverse impacts of oil and gas development. To this end, this programmatic environmental statement should:

1. provide the rationale and environmental factors utilized in the selection of OCS areas to be leased (and in the selection of tracts within areas), and
2. detail the environmental studies to develop baseline information on virgin areas, and the means by which these studies will be used in the decision-making process on area and tract selection.

EPA strongly encourages DOI to consider the preparation of environmental statements for each of the proposed OCS areas to be leased in order to assess the full impacts of oil and gas development within these areas. These statements would include the cumulative primary and secondary impacts of individual lease sales, including onshore impacts, identify those tracts where oil and gas development would have significant detrimental environmental impacts, and identify those tracts of resource potential conducive to safe development. Such statements could be prepared in conjunction with developing a leasing schedule for the area or accompany the first leasing sale in the area.

The present programmatic environmental statement should also assess administrative alternatives to the present EIS preparation system that would improve the usefulness of EIS preparation and review with respect to OCS oil and gas development. At present, tract nomination and selection are determined primarily by industry interest and hydrocarbon potential. It is our view that environmental considerations are not as yet a meaningful part of the area and tract selection processes.

Further, impact statements prepared in connection with lease sales can often do little more than project

very general consequences of operating plans. There is little information to predict cumulative impacts, location of pipeline corridors or onshore development. The present system, which ties exploration and development to a single leasing system, with the EIS process generally applied to the lease sale, can lead to the undesirable consequences that exploration is held up while development issues are debated, or the government's commitment to exploration (and subsequent development) proceeds through the leasing system with inadequate consideration of environmental consequences and mitigating alternatives.

We request that consideration be given to the benefits of a dual EIS system and to the separation of exploration and development decision processes (to the extent that this is possible under existing law) in order to facilitate reasoned decision-making about oil and gas development and the means to avoid or mitigate adverse environmental effects. For example, an EIS prepared after tract nomination but before tract selection is finalized would focus on marine biological aspects and accomplish the early examination and screening of tracts that can be safely and profitably developed. To the extent possible within knowledge constraints, this statement would also evaluate development impacts.

Subsequently, EPA, State and public review of development plans and operating orders would be afforded and, if there were environmentally significant developments which had not been analyzed in the previous EIS, a developmental EIS would be submitted (perhaps on a development unit basis). This second review process would allow fuller consideration of pipeline corridors, coastal development, induced development and related environmental effects than is presently possible.

Finally, we believe that legislative alternatives which would facilitate consideration of environmental factors in selecting and developing areas should be addressed in the final statement. Several of these alternatives are listed below:

1. Two Title System: Frontier OCS regions would be divided into large blocks. Companies would bid for exploration permits for one or more blocks. At two-year intervals, the permit holder would be required to forfeit a percentage of the block to government control. The permittee would retain sole production rights to the remaining acreage. Issuance of a production license would be contingent on a public review of the environmental acceptability of the proposed production plan.

2. Exploratory Leases with Preference Rights:

Government would sell large areas to consortiums for exploration. Only exploratory lease holders would have the right to bid on developmental leases. Before production rights are granted, there would be a mandatory environmental analysis to determine if, and under what conditions, the leases could be produced.

3. Full Scale Governmental Exploration: The

government would contract with private companies to explore the OCS. Oil discoveries would be sold competitively as reserves in the ground, of an environmental analysis determines that energy benefits outweigh environmental costs.

The most beneficial administrative alternatives to the present EIS preparation system would be increased involvement of Federal and State agencies at the earliest possible point in the pre-sale process. "It is difficult to bring the EIS to bear at the call for nominations or tract selection stage, as these actions are used to arrive at a specific proposal, and in and of themselves, do not affect the environment. The system used consists of summary resource reports being prepared by Fish and Wildlife Service and NOAA before tract selection, and EIS preparation after tract selection that focuses on each individual tract included in the offering. Each site-specific EIS prepared for a proposed OCS sale contains a description of the tract selection process, including environmental factors, which are utilized in determining the proposed sale area. See especially pp. 9-14, V. I., Draft EIS for a Proposed OCS Lease Sale Offshore Southern California. Relative environmental risks are evaluated, and recommendations on inclusions or exclusion of each tract are offered. Strategies for area selection have been included in this final EIS based on leasing first for high hydrocarbon potential, leasing last the environmentally hazardous areas, and leasing to learn.

While the separation of exploration from development may not be possible under the OCS Lands Act, several measures have been

introduced in Congress that will directly or effectively amend the Act to achieve this separation. The Department is currently investigating what modifications can be made under existing law including a dual EIS system to separate exploration and development phases. It has been suggested, and indeed is permissible under law, for the USGS to require the preparation of an EIS on any or all development plans submitted by industry after leasing.

The three legislative alternatives suggested by EPA all center upon the critical questions... Should exploration be separated from development, and by what mechanism? The EPA suggestions cover the range of exploration only to exploration tied with strong development rights. However, the mechanism of separation is relatively unimportant from an environmental standpoint. This final EIS addresses the concept of segregation of exploration and development in detail in Section VIII on Alternatives.

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UNITED STATES
DEPARTMENT OF THE INTERIOR

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BUREAU OF LAND MANAGEMENT

NEW YORK OUTER CONTINENTAL SHELF OFFICE

TECHNICAL PAPER NUMBER 1



ECONOMIC STUDY OF THE POSSIBLE IMPACTS
OF A
POTENTIAL BALTIMORE CANYON SALE

DECEMBER 1975

PROPERTY OF
BUREAU OF LAND MANAGEMENT

This study concerns itself with the possible onshore impacts that the potential leasing of the Baltimore Canyon Outer Continental Shelf (Sale Number 40) could have on the Mid-Atlantic coastal region. The purpose of the study is to provide the reader with an understanding of the extent of the impacts that could be expected should the proposed sale occur. It is also the purpose of the study to flag some of the potential onshore problems that could stem from the proposed sale and provide a greater understanding of the factors that could determine the possible socio-economic impacts.

The study is based on an application of a Multiregional Multi-industry forecasting model that has been developed by Dr. Curtis C. Harris, Jr. of the University of Maryland. For the remainder of the study, the Harris model shall be referred to as the economic model. In reviewing a book written by Dr. Harris on the economic model, the Journal of Economic Literature has said:

The work addresses an important void in the literature. Its basic modeling approach is sound, and it rests on an impressively thorough empirical base.

The economic model has been operational for several years. It has been previously applied by Dr. Thomas Grigalunas of the University of Rhode Island in assessing the potential impacts of Georges Bank exploration, development, and production on the New England region.¹ Another major application of the economic model was made by the Federal Highway Administration in a study analyzing the regional economic

¹See Thomas A. Grigalunas, Offshore Petroleum and New England, University of Rhode Island, Kingston, Rhode Island, 1975.

effects of alternative highway systems.¹ Further application of the economic model has been made by a study designed to trace the economic effects of locating strip mining coal production in Montana.² The economic model has also been used to study natural gas curtailment in Maryland.³ Impacts of the Public Employment Program on the economies of selected areas were analyzed using the economic model.⁴ An additional application of the economic model was made to study the impact of reduced agricultural production on the Southwest economy.⁵ A Canadian version of the model is being developed by the Ministry of State Urban Affairs in Ottawa, Canada. The model should be completed by the summer of 1976.

¹See Curtis C. Harris, Jr., The Regional Economic Effects of Alternative Highway Systems, Ballinger Publishing Company, Ballinger Publishing Company, Cambridge, Massachusetts, 1974.

²Anthony C. Fisher and John Krutilla, "A Preliminary Investigation of the Economic, Demographic and Fiscal Impacts of Eastern Montana Coal Development." Paper presented at the Regional Science Association Meetings, Cambridge, Massachusetts, November 7-9, 1975.

³William A. Donnolly and Ali M. Parhizgari, "Estimating the Regional Impacts of Energy Shortages." Paper presented at the International Regional Science Conference on Energy and Environment in Louvain, Belgium, May 1975.

⁴"An Evaluation of the Economic Impact Project of the Public Employment Program." Final Report by the National Planning Association to the U.S. Department of Labor, Manpower Administration, Office of Policy, Evaluation and Research.

⁵W.L. Harris et al., "Application of Solar Energy in Agriculture: A Research Program." Report to the Agriculture Research Service, forthcoming December 1975.

For purposes of this study, a scenario is hypothesized for input into the economic model. Information needed to formulate an actual development-production plan is not available until after drilling commences. It is only at this point that such a plan can be formulated. The assumptions presented for use in the economic model are not based on an actual development-production plan. For purposes of a pre-drilling study, a scenario is hypothesized that represents one of many possible scenarios that could be considered reasonable.

It is used as input into a predictive model only to suggest the impacts that a given scenario may have. The economic model is not predicting what will happen but could do so once an actual development-production plan was formulated. It is only suggesting what could happen given the hypothetical scenario that was developed. Results of the economic model should not be taken as a policy statement and are in no way urging or implying that an actual development-production plan to be formulated in the future should or will contain the factors of the hypothesized scenario used for the economic model.

The Mid-Atlantic coastal region is a frontier area in that no previous OCS lease sales have been held in the region. The need for a more rigorous framework with which to assess the possible socio-economic impacts of a potential Baltimore Canyon sale has become apparent. Each region within the United States is unique with regard to its existing economic structure. The impacts that could be expected from the possible introduction of offshore operations vary with the input-output relationships and industrial linkages that are found in differing areas. Many of the activities needed to support new investment activity in the Gulf of Mexico, for example, can already be found to exist in that area.

The same investment in a frontier area such as the Mid-Atlantic coastal region would induce substantially different onshore impacts. The economic model is used to capture the existing economic structure of a region and trace the impacts of a given scenario through the economy of the region in a consistent manner. In so doing, the extent of the impacts, potential problems, and factors determining the impacts can be identified.

While some readers may disagree with the set of assumptions used and have inherent difficulty with the concept of using an economic model to assess the possible future onshore impacts of the potential sale, the results of the economic model have been found to be quite reasonable given the assumptions used.

It is hoped that the methodology used will be considered as a beginning and further refinements, improvements, and adaptations can be made by users as greater certainty becomes available over time. This methodology should become more useful should development-production plans come into being and cost data become better known over time. Models of field activity could possibly be utilized for input into the economic model. Coefficients and relationships within the economic model could be adapted and changed to more accurately describe a given situation should more perfect knowledge become available. The output of the economic model could be used by planners as input into other models to further analyze the potential impacts.

The methodology used adds rigor to the way in which socio-economic

impacts have been assessed in the past. The analyst is forced to explicitly consider the activities involved in exploring, developing, and producing offshore oil and gas and trace the actual flow of these resources to onshore areas. It is hoped that in so doing a better understanding of the possible socio-economic impacts can be gained. This methodology could prove useful in other resource leasing programs and other potential leasing areas of the OCS.

The study is divided into four chapters. Chapter I describes the economic model used. Chapter II describes the assumptions used as input into the economic model. Chapter III provides the results of the economic model as well as an analysis of the model's output. Chapter IV describes an application of the economic model's results in the assessment of the possible level of air and water pollution emissions in four primary impacted counties that is consistent with the level of economic activity resulting from the hypothesized scenario. A final section summarizes the findings of the economic study.

It should be remembered that economic data does not include all values that society may deem to be important. Economic data measures production and not social welfare. It is suggested that the results of the economic model be used as just one of the important social indicators. In reaching a decision with regard to the leasing of the Baltimore Canyon Outer Continental Shelf, other social goals must be weighed against the goal of reaching a high level of gross regional product. With this in mind, the results of the economic model can be studied and analyzed in their proper perspective.

Both scenarios (with and without Baltimore Canyon activity) are based on wellhead prices of \$11 per barrel for oil and \$1 per thousand cubic feet for gas. In order to derive the total persons employed, it was assumed that the civilian unemployment rate will rise to 9% in 1975, fall to 5% in 1980, rise to 6% in 1985, after which it will return to 5% in 1990. The with Baltimore Canyon activity scenario is consistent with the following set of assumptions:

Recoverable resources of oil for the entire Baltimore Canyon are assumed to be from 3 to 5 billion barrels. Recoverable resources of gas for the entire Baltimore Canyon are assumed to be from 15 to 25 trillion cubic feet.

In formulating a production schedule for oil and gas, USGS used the midpoint resource estimates of 4 billion barrels of oil and 20 trillion cubic feet of gas for the entire Baltimore Canyon. It was assumed that the area offered for sale would contain 80% of these levels of recoverable resources. It was further assumed that the area actually leased would contain 80% of these levels. The level of recoverable resources of oil was therefore assumed to be 2.6 billion barrels of oil and 12.8 trillion cubic feet of gas. These estimates were made by USGS before the tract selection process for Baltimore Canyon Sale Number 40 was completed. They were derived using a modified Hendricks method. An explanation of the Hendricks method can be found in USGS Circular 522.

USGS has since revised these estimates downward to include more complete information obtained from the tract selection process. A range was provided of .4 to 1.4 billion barrels of oil and 2.6 to 9.4 trillion cubic feet of gas. These estimates were obtained by using actual geophysical data and comparing the estimated acreage within closure to success ratios and historical field data in already producing areas. For purposes of our study, the high initial pre-tract selection estimates were used so as to include a high impact case within the study. The reader should be reminded, however, that recoverable resource estimates in totally untested frontier areas are founded on very limited scientific or technical data and accordingly have a high degree of uncertainty.

2. Production of oil and gas is assumed to commence in 1981, peak to a level of nearly 740,000 barrels of oil per day and 4,400,000 thousand cubic feet of gas per day in 1989 and 1990, and end in the year 2000.

This assumption is consistent with the recoverable resource ranges used in this study. It represents a reasonable production scenario hypothesized by USGS for purposes of this study and is consistent with the recoverable resource estimates of 4 billion barrels of oil and 20 trillion cubic feet of gas. Table 2 provides the hypothesized production schedule of oil and gas used in the study.

Table 2

Hypothesized Annual Production Schedule

	<u>Production</u>	
	<u>Oil</u> <u>mm bbls</u>	<u>Gas</u> <u>mm mcf</u>
1981	25	20
1982	50	40
1983	80	140
1984	110	600
1985	140	800
1986	170	1,000
1987	220	1,200
1988	270	1,400
1989	270	1,600
1990	270	1,600
1991	250	1,200
1992	220	800
1993	170	400
1994	110	400
1995	90	400
1996	60	320
1997	40	280
1998	25	240
1999	15	200
2000	15	160
	2,600	12,800

3. All prices and costs are given in 1974 dollars and were converted to 1972 dollars before being used as input to the economic model. The output of the economic model is in terms of 1972 dollars.

This is a standard way of holding real prices and costs constant over time for analytical purposes. It is done so that the price or cost of a particular good or service relative to the cost of other goods and services in the economy remains constant over time. The "real" value of a particular good or service is assumed not to be eroded by a rise in the cost of living.

4. The price of oil is assumed to be \$11 per barrel at the wellhead. The price of gas is \$1 per thousand cubic feet at the wellhead. assumed to be

These prices were used in the Project Independence Report completed in November 1974. They represent a scenario that would promote accelerated energy supply development and energy consumption conservation. It is assumed for purposes of this study that these high prices will be maintained over time. Research and development is assumed to be undertaken so as to develop alternative energy supplies in the long run.

The leasing of the Baltimore Canyon could be seen as an intermediate solution to the energy problem in that it could buy more time until these alternative sources of energy are developed in the long run. A short run solution to the energy problem is reflected by the high prices assumed and their dampening effect on consumption. At higher prices less oil and gas will be demanded, other factors remaining constant.

3. Existing harbor facilities are assumed to be used to support the initial years of exploration at Philadelphia County, Pennsylvania, Kings County, New York, and Union County, New Jersey.

This assumption seems logical in light of the availability of port facilities in these counties and the need to invest capital only after it is determined that the amount of recoverable oil and gas is sufficient to warrant the heavy capital expenditures needed to support OCS production and development. Operators are assumed to be in a strong discovery situation with the development of reserves being expedited.

4. Onland operations bases able to support exploratory and development operations and the production of 200,000 barrels of oil per day are assumed to be built as follows:

- a. 1 in Atlantic County, New Jersey in 1979
- b. 1 in Kings County, New York in 1983
- c. 1 in Cape May County, New Jersey in 1985
- c. 1 in Monmouth County, New Jersey in 1988

The selection of areas to be described was not developed in concert with petroleum industry representatives or any individual counties or States. It was, however, a consolidation and weighing of information supplied by all such sources. In no way should it be construed as a designation of sites which will ultimately be used for operation base purposes. It is merely an evolution of reasonable case assumptions based on the best available data. The ultimate authority for siting lies with State and local governmental entities.

The Offshore Operators Committee supplied information regarding requirements and/or desirable factors that would be taken into consideration in locating possible operations bases. Hopefully, several assumptions which were made express State and local, as well as Federal, concerns in the siting of onshore facilities.

5. Gas and oil is assumed to be carried in separate pipelines with separation of oil and gas in associated wells occurring at the wellhead. All of the gas produced is assumed to be processed.

Market conditions are assumed to provide economic incentives for gas producers to process all gas that is produced. Gas is assumed to be produced from associated and non-associated wells. Separation can either occur at the wellhead or onshore. For our purposes the former was assumed.

- Large pipelines within four pipeline corridors are assumed to stem from four gathering points.

This assumption reflects a case in which oil and gas resources are widely distributed and are in sufficient quantities in each area to be commercially recoverable. The rate and distribution of OCS oil and gas production determine the number and location of gathering points that would be used as foci for the transportation of oil and gas to shore. Small gathering lines are assumed to be used to transport oil and gas to these centralized points. Large pipelines would then carry the oil and gas to shore within pipeline corridors. The nature of a particular corridor would depend on

the rate and distribution of OCS oil and gas production and require planning and coordination among Federal, State, local, and industry officials. Future pipeline corridor management planning studies would delineate specific pipeline corridors. Explicit in these future studies would be the information of an actual development-production plan (both onshore and offshore). The establishment of any pipeline corridor would require the formulation of a development-production plan by industry and its thorough review by Federal, State, and local officials.

17. Pipelines are assumed to be built as follows:
 - a. 225 miles of pipeline built from an OCS gathering point to the Atlantic County, New Jersey terminal, Atlantic County, New Jersey gas processing area and existing gas distribution lines, and a port of Philadelphia/Delaware area refinery (Philadelphia County, Pennsylvania) in 1980
 - b. 185 miles of pipeline built from an OCS gathering point to the Monmouth County, New Jersey terminal, Monmouth County, New Jersey gas processing area and existing gas distribution lines, and a port of New York/New Jersey area refinery (Middlesex County, New Jersey) in 1981
 - c. 200 miles of pipeline built from an OCS gathering point to the Cape May County, New Jersey terminal, Cape May County, New Jersey gas processing area and existing gas distribution lines, and a port of Philadelphia/Delaware area refinery (Gloucester County, New Jersey) in 1982
 - d. 200 miles of pipeline built from an OCS gathering point to the Ocean County, New Jersey terminal, Ocean County, New Jersey gas processing area and existing gas distribution lines, and a port of New York/New Jersey area refinery (Union County, New Jersey) in 1983

Pipeline mileage was calculated by locating actual gathering points that were centrally located in four different areas of the potential

leasing area and measuring the distance of hypothetical oil pipeline routes through terminal areas to refinery areas receiving the crude and the distance of hypothetical gas pipeline routes through gas processing areas to existing distribution lines allowing some extra mileage under the assumption that the most direct route was not always feasible due to environmental considerations. Onland pipeline mileage was estimated for each county.

Pipeline land terminals each with a capacity of 200,000 barrels of oil per day are assumed to be built as follows:

- a. 1 in Atlantic County, New Jersey in 1980
- b. 1 in Monmouth County, New Jersey in 1981
- c. 1 in Cape May County, New Jersey in 1982
- d. 1 in Ocean County, New Jersey in 1983.

Wells are assumed to be capped until pipelines are built.

Productive levels of each field are assumed to be established during the exploratory phase with pipeline needs foreseen at this time. Large diameter pipelines (32 inches) are assumed to be laid and onland terminal facilities constructed just prior to production and during the first few years of production so that they would all be operational as production increased to peak levels.

Industry, in deciding where to locate a pipeline land terminal, would consider sites at which greater profits could be achieved than would be possible if it were located elsewhere. It is therefore

likely that coastal areas adjacent to the Baltimore Canyon would be preferred by industry. If localities are receptive to these new facilities, they may still be expected to place conditions upon industry entering the area. To the degree that these conditions place costs upon firms that favor a particular location, these firms may or may not find it profitable to locate in a particular locality.

In deciding whether a particular site is desirable, a firm will consider the transportation costs of its inputs and outputs. The firm will seek to minimize the transportation costs of shipping goods and services to where they are needed and the transportation costs of the materials needed to provide these goods and services. Cost of labor is also a consideration. Wide differences in the cost of labor can be found in the Mid-Atlantic coastal region. No wage rate has been established within the area for many of the economic activities needed. Firms will seek to have wage rates high enough to attract persons having the needed skills but in areas where wage costs would be minimized. It is likely that areas with lower labor costs will provide an incentive for firms to locate in a particular locality. The presence of unemployment in an area might also tend to lower the amount of wages that an entering firm would need to pay.

In order to gain a more favorable location, however, a firm may be required to pay high acquisition costs to obtain a given parcel of land thereby eliminating any economic advantage to be gained by that site. Other things being equal, those areas with lower acquisition costs are more likely to be favored by a firm.

In selecting areas in which to locate pipeline land terminals for purposes of this study, the New Jersey coastal region seemed favorable with regard to the factors just discussed. In making an actual siting decision industry would weigh economic considerations against the zoning laws and physical characteristics that would accompany a particular parcel of land.

Production of oil is assumed to replace imports. Imports of oil are assumed to be decreased by the amount of OCS oil production.

The assumption is consistent with a policy of decreasing United States dependence on foreign sources of energy. This assumption will decrease the level of economic activity in the counties which are now used as a port of entry for the oil to be replaced. It will increase the level of economic activity in the counties in which terminals are built to handle the new OCS oil.

25. An exploratory well is assumed to cost \$3,000,000 to drill. Platform and production equipment with installation is assumed to cost \$20,000,000. A development well is assumed to cost \$1,200,000 to drill.

These costs were allocated by year to those counties in which onland operations bases were assumed to be built. Exploratory well drilling costs were allocated during the initial years to those counties that were assumed to support the initial years of exploration.

The initial estimates provided to us by USGS for exploratory well drilling and development well drilling were lower than those indicated above. Recent drilling costs in the eastern Gulf of Mexico area suggested that an upward revision of these initial estimates would be more indicative of costs to be expected in the Mid-Atlantic area. The estimate for the cost of platforms and production equipment with installation was provided by USGS. This figure includes gathering lines, pumps, and other production equipment.

26. The cost of laying large pipelines offshore is assumed to be \$1,000,000 per mile. The cost of laying large pipelines onshore is assumed to be \$300,000 per mile.

These cost estimates are consistent with industry data. They are in the high cost range of pipelines that have been built in recent years.¹ Offshore pipeline costs were allocated by year to those terminal counties receiving the pipelines. Onland pipeline costs were allocated by year to those counties in which pipelines were assumed to be built.

¹See Oil and Gas Journal, August 18, 1975, p. 66.

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The county's production increases by \$2.8 million in 1980, \$8.0 million in 1985, and \$10.9 million in 1990. Economic opportunity however induces persons out of the county in 1980 and 1985 and back into the county in 1990. Population levels are 355 and 386 below 1980 and 1985 base case levels and 319 above the 1990 base case level. All changes induced by Baltimore Canyon activity are less than 1 percent from base case levels.

Impacts on Urban Areas - Coastal Virginia

In Virginia, the only coastal areas experiencing induced industrial sector increases in output of greater than \$100,000 are Hampton City, Newport News City, and Norfolk City. The effects of Baltimore Canyon activity on Virginia are minimal.

Hampton City, Virginia
Induced Output Effects
(Dollars)

	<u>1980</u>	<u>1985</u>	<u>1990</u>
Personal Income	70,000	60,000	44,000
Earnings	62,000	66,000	40,000
Per Capita Income	1	2	2

Hampton City, Virginia
Induced Output Effects
(Thousand Dollars)

	<u>1985</u>	<u>1990</u>
Transportation		147
Retail Stores	149	255
	201	

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INTERROGATORY
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GOVERNMENT EXPLORATION OF THE OCS

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Office of OCS Program Coordination
March 10, 1975

I. Introduction and Conclusions

A. Introduction

Over the last year, there has been increasing interest in some kind of government exploration program for the OCS. Such a program is considered attractive primarily because it would retain public control over OCS resources until the location and extent of those resources is better known. At that time, resources could be sold for private development.

There appear to be three major reasons why it is considered desirable to retain public control over OCS resources until resources are better defined. These are:

- (1) to retain control over the decision to develop or not develop any given area, until there is better information about the extent of oil and gas resources, and about the magnitude of environmental and onshore costs of development;
- (2) to reduce the risks of any subsequent private development program, thereby increasing competition in resource sales, reducing the control of the largest companies over OCS resources, and insuring receipt of fair value by the public for any resources sold;
- (3) to provide better government resource information on which to base a national energy strategy.

Counterbalancing the apparent advantages of government exploration is the possible problem of inefficient or ineffective exploration under a government program. Government exploration would replace a large number of independent private oil explorers with a single bureaucratic institution. For certain economic activities, a single bureaucratic institution may be quite capable. However, for oil and gas exploration, there appear to be some unusual problems associated with a government-run operation.

This paper considers these issues of government exploration. First, in Section II, the oil and gas exploration process is described and illustrated with actual historical cases of exploration activity. Then, in Section III, three alternative government exploration programs are considered. Each of these is evaluated in terms of the perceived advantages of government exploration, cited above. Also, each is considered in light of the information presented in Section II in order to assess the potential difficulties that might arise from a government-run exploration program. Finally, in Section IV, a modification of the present leasing program is considered. This modification would realize some of the advantages seen in a government exploration program, without running the risk of inefficient or ineffective exploration by the government.

B. Conclusions

The information about oil and gas exploration presented in Section II indicates that exploration is difficult, and that success apparently depends, among other things, on subtle differences of judgment among

2626 oil explorers. Without these differences in judgment, particular prospects or whole areas might in the past have been prematurely condemned as not worthy of further exploration effort. Thus, maintaining a diversity of exploration strategies in any one area appears to be quite important to rapid and efficient discovery of oil and gas resources.

The record of oil discovery in the North Sea illustrates the importance of diversity in exploration strategies. The North Sea was not considered to be a very good oil or gas prospect as recently as 1959. At that time, however, a large natural gas deposit was found onshore in Holland, and this stimulated interest in the natural gas potential of the British sector of the North Sea. Exploration began there in 1964, and a number of large gas deposits were found between 1965 and 1969.

The oil potential of the North Sea was still not rated very highly, however, and most of the exploration interest was focused on the British sector where the prospects for natural gas were best. Nevertheless, a total of nine exploratory groups had been active in the Norwegian sector prior to 1969. By 1969, however, 29 dry holes had been drilled, and eight of the nine exploration groups had abandoned their activities in the Norwegian sector. The remaining group continued to drill, and in 1969, it discovered a large oil deposit which really opened up the oil potential of the North Sea. After this first discovery, other groups returned to the Norwegian sector, and stepped up drilling in adjacent parts of the British sector. Very

shortly thereafter, a number of additional large oil deposits were discovered. Today the North Sea has been proved to be a major oil province, with 16 billion barrels of oil reserves already discovered, and potential recoverable reserves estimated at 40 billion barrels or more.

The North Sea story dramatically illustrates the importance of diversity in exploration strategies. If decisions about the area had been reached by a consensus judgment, exploration would undoubtedly have been given up before the actual oil discovery took place.

Recognition of the importance of diversity in exploration strategies casts considerable doubt on the merits of any exploration program wholly or substantially run by the government. Such a program would certainly reflect a consensus judgment amongst geologists, and there would be little or no opportunity to test ideas that departed from this conventional wisdom. Thus, a policy of government exploration, though superficially appealing, would probably be a serious mistake. By replacing a diversity of competing strategies with a single strategy based on consensus judgment, government exploration could delay discovery of oil and gas in many cases, and might even prevent discovery in others.

Although government exploration would probably be a serious mistake, the suggested modification of the present leasing program, presented in Section IV, appears to merit further consideration. This modification would retain government control over the decision to develop any given area by withholding development rights until there is an implicit policy

decision that the net value of oil and gas resources in any given area exceeds the environmental and social costs of development. In this way, the modified leasing system would realize the first and most important advantage seen for government exploration, without risking the inefficiencies of such a program.

II. The Exploration Process

In considering government exploration programs of various kinds, it is important to have a basic understanding of the process of oil exploration. Typically, there is no simple formula for exploring in all prospective areas, or even for exploring different prospects within a given area. Moreover, the appropriate exploration strategy in any instance depends on information gained from prior exploration, and on improvements over time in exploration techniques. For these reasons, exploration in a given area is often a sequential learning process which may go on for years before any or all deposits are located.

In recent years, most exploration has begun with geophysical analysis which serves to identify geological structures which may contain oil. Until very recently,* geophysical techniques could not determine whether oil was actually contained in identified structures. However, the likelihood of oil existing was increased if prior drilling

* A recent advance known as "bright spot" analysis significantly improves the ability to predict the existence of natural gas in a structure. However, this technique does not allow reliable predictions of the amount of gas present.

experience in the area had found potentially oil-bearing sedimentary rock layers, or especially if oil or gas had been found previously in the area. The purpose of stratigraphic drilling is to obtain such information about rock layers as an aid in assessing geophysical data. 2629

Based on the geophysical information about structure size and shape, and using any available geological information from prior exploration or stratigraphic drilling, exploratory drilling is begun. Each exploratory hole drilled will determine whether or not oil exists in the vicinity of the hole, but not whether it exists nearby or at deeper levels under the surface. Even if no oil is found, however, each exploratory hole may provide valuable information on the nature of the rock layers in and around a given structure. Such information, combined with geophysical information about the structure, may suggest more appropriate sites for subsequent exploratory holes. After some point, however, if no oil is found, further exploration may begin to appear useless and exploration efforts on the structure will be abandoned.

The history of oil and gas exploration contains numerous cases where a structure is identified but initial drilling discovers no oil. Exploration activities are then abandoned by the explorer. Subsequently, after some time interval which may be short or long, another company will renew exploratory drilling on the prospect. This may be because the second company has a different idea about the appropriate exploration strategy or because some improvement in technology has made renewed exploration appear worthwhile. There are cases where this process has been repeated several times before a given structure is fully explored.

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An example of this kind of situation is described in a book containing case histories of discovery of stratigraphic oil and gas fields.^{1/}

The case concerns the San Emidio Nose field in California, which experienced an unusually long period before exploration of a structure was completed.

The structure was first identified in 1934 by the Ohio Company (now Marathon). Their exploratory hole, drilled in 1935, was apparently aimed at discovery of gas at shallow depths where Ohio had previously discovered gas in the same basin. This hole, however, was dry.

Over the next 15 years, five more companies together drilled six additional holes at progressively greater depths. While some of the drilling was hindered by mechanical difficulties, and none of the holes discovered oil, some of them did reveal traces of oil in certain sedimentary layers, and the geological information they produced was apparently a significant influence on the drilling decisions of subsequent explorers.

Finally, in 1957 and 1958, Richfield (now Atlantic Richfield) drilled two more deep holes, the second of which discovered the San Emidio field. This is the end of the story as of 1969 when the case history was written. However, the author of this case history was contacted recently, and he revealed that Texaco in 1973 or 1974 did further exploration work on the same structure and discovered a second field, the Yowlumne field, on that structure. Thus, it is even possible that additional discoveries could be made in the future, perhaps by yet another company, on this structure which was first identified and explored in 1934-1935.

This case history is conceded by the author to be somewhat unusual. However, it does seem to illustrate a number of important aspects of oil and gas exploration. First, differing interpretations of available geophysical and geological information apparently lead one company to explore where another has given up. Second, exploration decisions were part of a sequential decision process which took into account the results of previous exploratory drilling. Third, improvements in drilling technology no doubt helped overcome early mechanical difficulties encountered in drilling, and they also probably contributed to the progressively greater depth to which later exploratory wells were drilled, resulting in oil discovery.

The above case history illustrates certain aspects of oil and gas exploration for the case of a single identified prospect. However, the history of exploration in entire areas is also instructive of the nature of oil and gas exploration.

In the North Sea, for example, there was little interest by oil explorers as recently as 1959.^{2/} At that time, however, an extremely large gas deposit was found onshore in Holland. This, together with evidence from minor amounts of exploration and production onshore in Britain, indicated that the North Sea could contain substantial deposits of gas similar to that found in Holland. Thus, geophysical surveys of the North Sea were begun.

In late 1964, after countries with North Sea coastlines had set down ground rules for exploration, the first exploratory drilling began. Two major exploration strategies were followed by the various companies involved in exploration. Some companies concentrated their efforts on salt domes, a kind of geophysical structure in which Gulf of Mexico fields are typically found. Other companies looked at large anticlines. These are the kinds of structures in which the large Middle-Eastern discoveries were made, and it is the type of structure in which the gas deposit in Holland was discovered.

The first discovery was made by British Petroleum in December 1965. This discovery occurred on the British side of the North Sea rather than on the continental side, where the first holes had been drilled. However, the BP discovery did occur in the anticlinal type of structure, a type of structure with which BP had gained considerable experience in the Middle East. The BP discovery probably focused attention on anticlinal types of structures, and over the next several years, a number of other substantial gas deposits were found, mostly in British waters of the southern North Sea.^{3/}

The early successes in finding gas in the southern North Sea led explorers to view the whole area as of interest primarily for its gas potential.^{4/} With this perspective, the central North Sea, in particular the Norwegian sector, was not rated very highly as an oil or gas prospect.^{5/} Moreover, the chances of finding oil anywhere in the North Sea had always been considered poor.^{6/}

In spite of these common opinions about the oil potential of the North Sea, there was some exploration carried on in the Norwegian sector by a total of nine groups. By late 1969, these groups had together drilled 29 dry holes, and all but one had ceased drilling in the Norwegian sector, after fulfilling their work obligations.^{6a/} The remaining operator was Phillips, which had been the only company to have found any indications of oil potential in that area. In spite of having fulfilled its work obligation of 3 wells, Phillips was still drilling. Late in 1969, on its ninth well, Phillips discovered the large Ekofisk oil field in the Norwegian sector.

It was the Phillips discovery that really opened the oil potential of the North Sea. In the wake of that discovery, drillers returned to their abandoned blocks in the Norwegian sector, and stepped up efforts in the adjacent British sector of the central North Sea. Many more significant discoveries were made in rapid succession over the next two years. Also, the success in finding oil in the central North Sea sparked greater interest in the northern North Sea where significant discoveries began to occur in 1972.^{7/}

There appears to be some kind of a lesson in the North Sea oil experience. First, a large number of dry holes do not necessarily mean that an area will ultimately prove unproductive, particularly if it is a new area where there have been no prior discoveries. Second, there was a kind of conventional wisdom which said there was little hope of finding oil anywhere in the North Sea and little hope of finding gas except in the southern portion of the North Sea. This

2634 conventional wisdom may have contributed to the early abandonment of hope by most of the operators in the Norwegian sector. As a result of this conventional wisdom, oil might have gone undiscovered for many years in the North Sea, except for the apparent luck or skill of Phillips in finding the Ekofisk field after other operators had given up.

In fact, there are a number of historical instances where oil discoveries were not made for some period of time because the conventional wisdom held that there was no point in looking for oil in certain areas. Once Saudi Arabia and Kuwait were considered poor prospects because they did not have Asmari limestone, the reservoir rock in which the original Middle Eastern discoveries were made in Iran.^{8/} Libya was overlooked until fairly recently because it had no surface seepages which usually indicates the presence of underground oil deposits.^{9/} Oil discoveries in Nigeria occurred only after years of exploration by Shell and BP. However, once the right exploration strategy for that part of the world was discovered, many companies have been very successful in discovering oil in the Niger Delta, often on the first attempt.^{10/}

As these examples illustrate, oil exploration can contain surprises. Moreover, there is reason to believe that these surprises would not occur if exploration strategy always followed the conventional wisdom of any given time. Of course, that wisdom would change over time in many cases. However, it is likely that realignment of the conventional wisdom is accelerated, and possibly even caused, by some explorer who initially departs from the accepted strategies to try new ideas.

To summarize this discussion of oil exploration, there are three basic steps in oil exploration:

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- (1) geophysical work to identify structures with oil-bearing potential;
- (2) stratigraphic drilling to improve the ability to assess geophysical data;
- (3) exploratory drilling to determine whether or not oil exists and to provide additional geologic data for use in subsequent exploration.

Case histories of exploration on particular structures illustrate three significant aspects of oil and gas exploration:

- (1) different interpretation of the same data by different companies leads to testing of a number of different exploration strategies, if initial exploration is unsuccessful;
- (2) exploration is a sequential learning process which takes into account all information previously obtained from exploration of the structure;
- (3) technological improvements in exploratory techniques lead to more effective exploration over longer periods of time.

The case histories of exploration in large areas point out a final aspect of the oil exploration process:

There are often very productive areas in which discoveries would never be made if everyone adhered to the contemporary conventional wisdom about these areas. Clearly, the conventional wisdom does change over time, but this may be only because some explorer departs from the conventional wisdom to disprove it.

2636 III. Alternative Government Exploration Programs

A. Limited Stratigraphic Drilling

Stratigraphic holes are most valuable as a means of interpreting geophysical data, primarily that obtained by seismic techniques. Seismic techniques use sound waves to develop a picture of the contours and thicknesses of underground rock layers. This picture is produced because sound travels at different speeds through different layers, and it is reflected back to the surface by the juncture between layers. However, until a hole has actually been drilled through the rock layers, the exact speed of travel of sound through these layers is unknown. Thus, the information obtained from a stratigraphic hole makes inferences from sound reflections much more reliable, and in addition reveals any unexpected rock layers which might have been overlooked in the original interpretation of the seismic data.

It is interesting that stratigraphic holes are seldom drilled by the oil industry, especially in offshore drilling. Instead, the first hole drilled on a new prospect is usually sunk where the seismic data, no matter how unreliable, indicate there might be oil. This is a reasonable approach, since a hole drilled in search of oil will tell as much as one intended to sample the rock layers, and there is some added chance of finding oil if the hole is drilled where there might be oil.

Recognition of this fact raises some question about the usefulness ~~26~~37
a government program of stratigraphic drilling. However, such a program, combined with appropriate data disclosure regulations, might serve to make OCS lease sales more competitive by eliminating some possible informational advantages enjoyed by the larger companies.

It is possible, for instance, that the larger companies are better able to interpret seismic data without the aid of information obtained from stratigraphic drilling. In addition, it is likely that the larger companies will have drilled a hole nearer to any given lease up for sale, simply because the larger companies have drilled more holes. With geologic information from a nearby hole, a company would have an advantage in interpreting seismic data from a prospect being offered for lease.

Any advantage of the larger companies could be reduced or eliminated by a combined program of stratigraphic drilling if no holes had been drilled previously in the vicinity of a sale, or with a requirement that geologic data be made public if any nearby holes had been drilled.*

Stratigraphic drilling thus might be a means to reduce information advantages, and increase the competitiveness of OCS sales. By doing so, it would provide greater assurance that the government is receiving fair value for leases sold, and it would tend to break up alleged control of oil supplies by the oil companies.

* Currently, the Department of the Interior is developing regulations which would require such data disclosure.

2638 On the other hand, a stratigraphic program would tell us little about the production potential of any given region. Thus, it would contribute little to development of a "national energy strategy." Also, stratigraphic drilling would not increase government control over decisions affecting the environment or onshore development.

B. Actual Government Exploration for Oil and Gas

The next logical step, after a stratigraphic drilling program, is to drill some holes on identified structures where there is some possibility of finding oil. There would appear to be two reasonable alternatives:

- (1) Limited government exploration of certain selected prospects, followed by competitive leasing of the area to industry.
- (2) Complete government exploration of all prospects, followed by leasing for development if oil is found.

While it would also be easy to specify a third alternative of drilling some fixed number of holes in an area, such an alternative would seem to make much less sense than a program, such as alternative (1), to evaluate some specified number of the best prospects. Thus, only alternatives (1) and (2) are considered here.

These are considered in turn below.

- (1) Limited exploration on the best prospects, followed by competitive leasing in the area.

In general, there are two possible outcomes of this program. A discovery may be made on one or more prospects, or there may be no discoveries made at all. 2639

If a discovery is made, it will significantly improve the odds that the prospective area will become commercially productive. However, unless the discovery or discoveries are commercial by themselves, it is not at all certain that the area will prove productive in the end.

On the other hand, if no discovery is made, it does not necessarily condemn an area, though it does presumably reduce the odds that the area will ever be productive. For instance, about 30 dry holes were drilled in the Norwegian sector of the North Sea prior to the first significant oil discovery. Overall, the success rate for wildcat drilling is one-in-ten¹¹, and that presumably overstates the likely success rate for the first holes in a new prospecting area.

It is most likely, therefore, that the chief result of drilling, limited to certain selected prospects, would be a shift in the odds that a given area would ever be productive. It would be unrealistic to expect that limited drilling would produce a more conclusive result.

This likely outcome could create a political problem, however. After the government exploration program, there would presumably be some decision made about proceeding to lease the area for further development.

2640 If, in fact, the outcome of limited government exploration could never condemn an area as unproductive, then the area should certainly be leased for further exploration. However, unless the government exploration program had encountered some success, there would no doubt be strong political opposition to any leasing in the area. The result could be that the area would not receive any more exploration than that provided for in the limited government program.

Limited drilling would have to be done, of course, by private companies contracting their offshore drilling resources to the government program. In many cases, the contractors would be potential bidders in any subsequent bidding for leases in the area being explored. This could raise a problem in such bidding, if it placed the contract drillers in an advantageous position as a result of their better understanding of the geology of the area or of particular leases. While public data disclosure would mitigate this problem, it is unlikely that it could totally eliminate it.

It is hard to see any way that the limited program on selected sites would contribute importantly to formulation of a "national energy strategy," or importantly affect the handling of environmental and onshore development problems. The limited program would neither determine the productive potential of areas, nor would it give the government any greater control over the development and production decisions, should they ultimately be made.

(2) Complete government exploration of all prospects in a given area.

Complete exploration by the government, if it is thoroughly carried out, will determine the productive potential of an area. In this way it avoids the most important shortcoming of a limited drilling program. In addition, complete exploration would give the government more effective control over development and production decisions, since oil resources would still be owned by the government at the time of development decisions. ↵ 2641

Finally, complete exploration might provide greater assurance that prices paid for production rights would represent fair value, since there could be greater competition in bidding for discovered reserves than there currently is in bidding for riskier undiscovered reserves.

The potential risk with complete government exploration is that it would not in fact be carried out thoroughly and effectively. To understand this risk, it is important to keep in mind the nature of oil exploration as discussed in the second section of this paper. Oil exploration is not a simple, standardized procedure, and it often defies conventional thinking.

If the government, or any single institution representing diverse viewpoints, were to be given sole responsibility for oil exploration in a given area, it is certain that the exploration strategy adopted would reflect some kind of consensus judgment, i.e., the conventional wisdom. If so, then there is a risk of encountering a situation where the conventional wisdom does not work, resulting in a failure to discover substantial oil deposits. This kind of failure could occur

2642 on particular structures, or in whole areas, or both. Diversity of exploration strategies appears to play a role in success, both on individual structures and in whole areas.

There is, however, an additional kind of risk with government exploration. Because the government represents viewpoints of others besides oil explorers, there is a risk that a consensus exploration program might not even reflect the conventional wisdom about oil exploration. For instance, environmental or coastal interests might see the negative impacts of oil development as outweighing any possible gain from development, at least from their perspective. Thus, they would prefer an exploration program which is unlikely to find oil, and they would seek to abandon an unsuccessful exploration program as early as possible. If this viewpoint became reflected in a consensus exploration strategy, the result would be a strategy with even greater risk of failure than that associated with a strategy based on the conventional wisdom of oil explorers.

On the other hand, over a longer time span, there might develop other interests with a stake in maximizing the amount of exploration activity. For instance, the agency set up to run an exploration program would have a vested interest in maintaining it. Moreover, it is possible that drilling contractors and their home State political representatives might also develop an interest in maintaining the program, if a significant degree of excess drilling capacity develops at some time in the future.

In sum, the complete government exploration program is appealing at 2643 first glance. It could provide resource information, more effective control over decisions affecting the environment and onshore development, and greater assurance of selling resources for their fair value.

On the other hand, the history of oil exploration suggests there are significant pitfalls which a government program might encounter. Such a program would appear less likely to actually find oil than an exploration program carried on by a diverse set of independent explorers.

Finally, there are certain political considerations which suggest there is risk that a government exploration program would even depart from the ostensible goal of discovering oil. For the short run, the political influences would probably act to reduce the effectiveness of the program, while in the longer run, there is a possibility that the program could produce excessive drilling, simply to satisfy political interests vested in the program.

C. Competing Public Corporation

If there are advantages to oil exploration carried on by a diverse set of explorers, then government exploration programs which do not preclude this possibility might be desirable. One possible program would provide for a public agency to carry on exploration concurrently with private exploration, and perhaps to carry on development and production as well.

2644 Having a public operating agency on the OCS would likely increase the government's information about the exploration and production process. This might improve the government's skills in determining whether bids for OCS leases represent fair market value, and its skills in regulating development and production to protect the environment, promote orderly onshore development, and promote efficient resource use. Presumably, also, an operating public agency might give the government better information with which to judge allegations of collusion by private companies to withhold supplies and drive up prices. On the other hand, the existence of a public operating agency would provide little more information than is currently available to the government about national oil and gas resources.

There would be some significant problems encountered in designing a public operating agency. These will only be mentioned here without any attempt to resolve them. First, there would be the problem of determining which leases the government would explore and develop. Second, it would be necessary to have arrangements to make government explored land available for private exploration, in cases where no discoveries were made by the government. According to our knowledge of oil and gas exploration, failure to find oil by one explorer does not necessarily mean that no oil exists. Third, it would be necessary to define appropriate objectives for the public agency. There would no doubt be political pressures for various different kinds of objectives, not all of which would be explicitly stated by their proponents, in

part because they would not all be defensible. Two reasonable kinds of objectives might be to provide a representative government interest ²⁶⁴⁵ in each OCS area, or to attempt to compete directly with private companies, i.e., to maximize the difference between the value of oil found and the costs of finding it. Fourth, there would be a problem of defining appropriate ground rules for the agency: how it is financed, how its fiscal accounts should be set up, and so on. The ground rules would clearly depend on the objective which is defined for the agency.

If a public operating agency is seriously contemplated, problems such as those cited above will need to be worked out in detail.

IV. Modification of Present Leasing Program

The above programs are exploration programs of one sort or another. There is, however, a modification of the current leasing system which would accomplish the most important of the goals for government exploration. The modification would be to require companies to submit development plans and have them approved prior to the beginning of any development. This would give the government greater control over development and production, and this control could be used to increase the role of government in decisions affecting the environment and onshore development.

Under current law, the Secretary of the Interior has broad powers to regulate OCS activities in the interests of resource conservation.

Included is the power to order suspension of operations on leases. Thus, under current law, the Secretary could presumably approve or disapprove continued development of leases, based on a consideration of all resources involved in development: oil and gas, environmental resources, and affected onshore activities. If the Secretary found that the environmental and onshore costs of development exceeded the net value of the oil and gas, he could order suspension of development on the leases involved.

The actual assessment of development impacts would probably be best handled through an Environmental Impact Statement (EIS) process. In addition, it would be more appropriate to consider development decisions on a field by field basis rather than on a lease by lease basis. Considering decisions on a field basis would at least informally impose a unitization plan on the set of operators with interests in each field. This is because the approval of development on each lease would depend on an evaluation of the costs and benefits of development on all leases, and because approval of development would be delayed until the overall plan for developing the field were made clear.

The necessity of considering development on a field by field basis through an EIS process would necessarily delay development and production to some extent. In addition, there would also be a possibility that small but nevertheless commercial fields would be denied development

approval. Both of these factors would tend to reduce the commercial value, hence the bonus bids, of any given lease. However, this reduction would not likely be too large, since development approval would be in question only where the value of the oil and gas itself was not great enough to clearly justify environmental and onshore costs of development. Denying development rights only in these cases would not much reduce the value of an OCS lease.

In conclusion, there appears to be merit in a formal procedure to approve development after exploration has taken place. Such a procedure should be given further consideration since it responds to one of the most important reasons for initiating a government exploration program, without running the risks of inefficient and ineffective exploration carried on by the government.



Footnotes

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- 1/ Bazeley, William, "San Emidio Nose Oil Field, California," in Society of Exploration Geophysicists, Stratigraphic Oil and Gas Fields - Classification, Exploration Methods, and Case Histories, Special Pub. No. 10, (Tulsa, 1972).
- 2/ Cooper, Bryan and T.F. Gaskell, North Sea Oil - The Great Gamble, New York, 1966. This book contains a description of the early history of the North Sea discoveries.
- 3/ George, W. J., "Report on the 1972 Drilling Season," in North Sea Conferences 1 and 2, London, Sept. and Dec. 1972, p. 93.
- 4/ Oil and Gas Journal, 5/25/70, p. 311.
- 5/ Oil and Gas Journal, 11/10/69, p. 130.
- 6/ Callow, Clive, Power from the Sea, London, 1973, p. 72.
- 6a/ Oil and Gas Journal, 10/11/69, p. 130.
- 7/ George, p. 93.
- 8/ Cooper and Gaskell, p. 32-33.
- 9/ Ibid.
- 10/ Ibid.
- 11/ Callow, p. 65.

Pages 5-10 - The point is well made that exploration is a highly subjective proposition, greatly dependent upon the evaluator's abilities and experience, and that different interpretations of the same data may vary considerably resulting in drilling and exploration programs differing even more.

Page 11 - The last paragraph alludes to an important point, but omits any further analysis. The point is this: is there a real need for stratigraphic drilling? "A hole drilled in search of oil will tell as much as one intended (merely) to sample the rock layers." This implies that a limited stratigraphic drilling program as identified in the Government Option A may be a superfluous activity. Granted, the stratigraphic test can provide information, but will the cost to the Government of conducting these tests merit activation of a government stratigraphic testing program? Reasonably, it would seem that the Government would get more for its money if it drilled each well "in search of oil" as the industry does and not simply to sample the strata. If the well is a successful producer, the competition may be enhanced because companies would be bidding on a tested structure with proven shows of hydrocarbons. If the hole is dry, further exploration is not precluded because the information obtained, assuming it would be made available to bidders, could be utilized by the prospective bidders

in evaluating their own bidding bases. As the author of the paper points out: "the first hole drilled on a new prospect is usually sunk where the seismic data, no matter how unreliable, indicate there might be oil. Since a hole drilled in search of oil will tell as much as one intended to sample the rock layer, and there is some added chance of finding oil if the hole is drilled where there might be oil." Essentially, the oil companies don't spend money on stratigraphic tests in unpromising areas; why should the Government? If the Government is really seriously pursuing an exploration program, design the program to search for oil, not merely test the strata.

Page 12 - Furthermore, the tentative data disclosure regulations are of questionable propriety. No matter how one views the advantages of large companies or small companies, the fact remains, the large companies will continue to have advantages. In such an inexact science as geophysical and stratigraphic interpretation, there is too much leeway in which large companies can prevent the disclosure of exploratory data. And if the regulations are made stringent enough to guarantee the disclosure of all company - gleaned information, such an oppressive policy may well reduce the total level of information rather than reduce the information advantages of the larger companies. Companies unwilling to release information will undoubtedly find ways to circumvent loose regulations, or worse, in the case of overly oppressive regulations.

may reduce or eliminate information gathering activities altogether because they would no longer find it economical to pursue information they must freely divulge. This may reduce bonus bids because the higher risks that would result from having less information would tend to increase the uncertainty of finding reserves.

Thus, these weaknesses should be mentioned in connection with any testing with data disclosure regulations. The paper in review may not have fully brought these points to the fore. The summary at the top of page 13 is correct in saying that "a stratigraphic program would tell us little about the production potential of any given region...(and) would contribute little to development of a 'national energy strategy.'"

The discussion of Option B(1), limited government exploration, recognizes, as far as we can tell, all the important points. If a discovery is made on a limited exploration program, it will improve the odds that the area will be commercially productive. If no discovery is made, the cost to the Government of drilling the wells may not be worth the information obtained.

Page 16, second paragraph - Complete exploration on the part of the Government may assure more fair prices received for production rights, and increase competition but not necessarily would it be a guarantee.

It must be recognized and should be pointed out in the paper that complete exploration may not change the competition. Again, the determination of oil field development is such a subjective process that additional information, although it could enable a better evaluation, may not

provide equal advantage to all and the cost to the Government may not justify the return, especially in cases where years of failure are followed by a discovery. In these cases, the Government would bear the total exploration cost. Furthermore this paragraph assumes that risk is the main factor limiting competition on the OCS without developing or stating a source for the idea. Risk is important, but probably equally important is the high cost of exploration, development, bonus, etc.

It would perhaps be appropriate to develop as another Government option or sub-option a program whereby the Government drilling program would concentrate on areas of poor potential rather than areas of good potential. This would be in keeping with one of the main points of the paper, i.e., that it often takes considerable perseverance to find hydrocarbons and one company may find reserves where numerous others have failed.

Extending this idea, the tentative Government drilling agency could be charged with exploring precisely these "bad" areas that draw no bids in a lease sale. Though such a program may never be implemented, it is nevertheless, an option that merits consideration, perhaps as Option B(2) making the present B(2), Option B(3). (page 13).

A discussion of the environmental aspects of Government exploration options would enhance the paper. It would perhaps be desirable to relate or analyze the relative environmental impacts of industry programs as opposed to the Government programs discussed. Basically, the question to be answered is: "can the Government, via its own exploratory drilling programs, achieve better environmental protection?"

Probably one of the most inhibiting factors in any decision for a Government drilling program is efficiency and cost. The paper is necessarily incomplete without this analysis.

Page 4, line nine - should omit "but not whether it exists nearby or at deeper levels under the surface." This statement is misleading. If it is not omitted, it should state that deeper levels can be explored by extension of the wells and the terms "vicinity" and "nearby" should be better defined.

Page 8, line 8 - A brief explanation of the British leasing system might enhance understanding of a lessee's "work obligation."

Page 11 - Either discussion of the mechanics of strat-testing or the discussion of why industry does not drill many strat holes or both, organizationally may be more appropriate in the exploration section of the paper and briefly mentioned in part III A.

Page 12, lines 21-22 - It seems inappropriate to make statements without explanation such as "and it would tend to break up alleged control of oil supplies by the oil companies". This statement, without explanation is misleading, for in a private enterprise system, is it not the oil companies' business to control its supplies of oil? The statement implies wrong doing and therefore should state that there is

or is not alleged wrong doing. In any case, an explanation is needed.

Page 17, second paragraph - This paragraph which states that environmental and control interests would prefer an exploration program unlikely to find oil, seems an unfair prejudgement of the groups and this is, we feel, inappropriate in an issue/options paper.

Page 1², line 8 - How would the government do this? I.e., in what ways would the Government judge alleged collusion by companies?



United States Department of the Interior

OFFICE OF THE SECRETARY
WASHINGTON, D.C. 20240

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JUN 20 1975

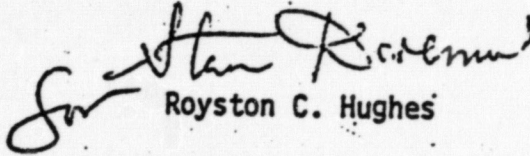
Memorandum

To: Assistant Secretary -- Energy and Minerals
Deputy Assistant Secretary -- Energy and Minerals
Director, U.S. Geological Survey
Solicitor
Assistant Secretary -- Land and Water Resources
Director, Bureau of Land Management

From: Assistant Secretary -- Program Development and Budget

Subject: Position Paper on Separation of Decisions to Explore
and to Develop OCS Areas

We have prepared the attached draft position paper for presentation to Secretary Hathaway with recommendations on the issue of providing a separation between OCS exploration and development. Would you please review the draft and provide your comments at the meeting scheduled for Tuesday, June 24, at 11:30 a.m. in Room 4119.


Royston C. Hughes

Attachment



Save Energy and You Serve America!

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Executive Summary

This paper presents four options for departmental action in response to proposals that OCS exploration and development decisions be separated to provide a more orderly process for coordinating State and Federal decisions on development and production of OCS oil and gas. The four options are:

- I. Business as usual with improved informal cooperation with the coastal States.
- II. Short Review Period: 90 days provided for States to comment on development plans.
- III. Moderate Review Period: 180 days provided for States to comment consistent with timing under Coastal Zone Management Act.
- IV. Extended Review Period: 180 days for States comment plus mandatory Environmental Impact Statements and public hearings on all development plans.

It appears that Option III would mesh best with the requirements of the Coastal Zone Management Act while minimizing the amount of time and effort devoted to preparation of additional environmental impact statements and conduct of public hearings.

Position Paper on Separation of Decisions
to Explore and to Develop OCS Areas

I. Introduction

Spokesmen for the coastal States have expressed a number of concerns with the accelerated leasing and development of OCS oil and gas. Many of these concerns stem from feelings^{that} the Federal leasing actions set in train a series of events over which the States have little influence or control, events which may force hasty and ill informed decisions on the part of State and local authorities. California, for example, has requested formal separation of exploration from development as one of the conditions for its cooperation with the accelerated leasing program.

Although there are currently in operation procedures at both the Federal and State level which provide some control over OCS development after sale of leases, proposals have been made that a stronger and more formalized separation be provided between decisions to explore OCS lands for oil and gas and subsequent decisions to develop, produce and land oil that is found.

An early proposal called for government exploration of the OCS with leasing to private industry for development and production of proven reserves. This arrangement offered the advantage of making the development decisions with full public knowledge about the magnitude of the reserves and without prior

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commitment to development even if oil were found. Several strong disadvantages led to its rejection, among them the cost of a government program, the lack of staff, and especially the advantages of the existing highly diversified exploration process.

The Congress is in the midst of drafting and debating modifications to the OCS Lands Act and the Coastal Zone Management Act which would substantially alter the procedures for review of industry development plans and issuance of development permits by the Secretary. One proposal requires submission of development plans including assessments of economic, social and institutional impacts, the preparation of an environmental impact statement and public hearings in affected coastal States. It is also proposed that the Secretary be given the authority to modify or disapprove development plans, compensating the lessee for his exploration costs if disapproval is upheld in the Court of Appeals.

It appears that many of the desirable features of separating exploration and development decisions can be achieved within the terms of existing legislation. The Interior Department Solicitor's office has indicated that the Secretary has broad authority in setting the terms of OCS leases, that except for an open-ended suspension or a permanent prohibition of development, the leases could legally provide for a pause between exploration and development "in the interest of conservation."

A commitment to develop and implement such procedures under existing law offers several advantages. It would be a positive response by the Department to the expressed concerns and desires of the coastal States which prefer to delay OCS leasing. In addition, it would force a detailed resolution within the Department of the many issues involved. Such a resolution would be of value in responding to congressional proposals, but more importantly, it would yield a department action even if congressional proposals fail to pass. Procedures to provide for more interaction among Federal, State and oil industry officials may offer enough advantages to warrant their eventual implementation one way or another. Preemptive or obstructionist policies taken by any of the three parties are likely to lead to inefficient and more risky patterns of production. If decisions can be worked out cooperatively with joint consideration of the relevant data and the views of affected parties, better decisions are likely to result for the entire system of offshore and onshore activities needed to produce oil and provide supporting infrastructure.

A major advantage of a formal pause between exploration and development is that it provides a specified pause and schedule for decision points which the lessees can rely upon in their preparations to implement development. Submission of development plans can be made the required period in advance of the decision point thus avoiding any actual delay

in construction if approval is granted. In contrast, the indefinite delays likely to result from litigation and other actions taken to delay and control development under current procedures create an uncertainty that makes preparations for construction of major facilities difficult.

The objectives of separating OCS exploration and development decisions stem from the goal of providing a more orderly and timely process for Federal and State decisions about the offshore and onshore developments necessary to produce OCS oil. These objectives include:

1. providing information requested by States for their review and planning;
2. coordinating the timing of Federal and State decisions so that Federally permitted offshore activities and State and locally permitted onshore activities taken together comprise an efficient and environmentally sound system;
3. avoiding undue delays between exploration and development by establishing an orderly process in place of the current situation of uncertainty and conflict.

The body of this paper will discuss the major options for separating exploration and development under existing law and will describe the strategic aspects of making a commitment now to establish such a separation.

II. Major Options for Separating Exploration and Development

In the preliminary discussions of this issue, a number of possibilities have been considered. Four major options appear to fairly represent the range encompassed in these discussions. In presenting these options, it is useful to specify the following elements:

1. The schedule for review and approval of development plans;
2. The relationship between the schedule and the requirements for Environmental Impact Statements (EIS) under the ^{National Environmental Protection} Act (NEPA);
3. The relationship between the schedule and the requirements for State concurrence with certification of consistency with ^{Coastal Zone Management Act} coastal zone management programs under the (CZMA);
4. The content of the plan and supporting data;
5. The size of the OCS area addressed by the plan.

The Coastal Zone Management Act is probably the strongest determinant of the schedule. It requires that applicants for Federal permits certify that the proposed activity will be consistent with federally approved coastal zone management programs prepared by the States. The States are given six months to indicate concurrence with the certification. During the six months, the issuance of a development permit could only be made in the absence of State concurrence if the Secretary of Commerce finds that the permitted activity is consistent with the objectives of the CZMA or necessary in the interest of national security. Thus, if the affected coastal States wish to delay the Department's issuance of a development

permit, they will probably be able to do so for six months if they have federally approved coastal zone management plans as most of them will by the time the development phase is reached.

The four options -- business as usual, short, moderate and extended review periods -- are each discussed in terms of these elements.

Option I: Business as Usual

This option would not provide a formal separation of exploration and development but would respond to State concerns by establishing more open informal relationships with the States. Separation of exploration and production decisions, in varying degrees of formality, has the potential advantage of permitting systematic and orderly consideration and certain Federal and State decisions, instituting a specific procedure for State/Federal cooperation, and expediting the process of expanding domestic oil and gas supply. However, the concept of separation is as procedurally complex as it is conceptually simple. The two phases of finding and producing hydrocarbons are not clearly separable processes in large areas. At best, separation can be achieved only on a field by field basis. Hence, one of the main voiced concerns of coastal States -- landside impact -- can only be ascertained incrementally. The full or perhaps even a significant portion of potential impacts could be determined only well into the future. Further, formal separation of decisions sets up a mechanism that could be exploited for additional substantial delays. Such a motive, at least on

the part of certain groups, must be perceived, especially as States within their sovereignty have or could establish authority to obtain on their own further controls over development onshore. One option thus to be considered is to proceed under current arrangements, but with as open a relationship with the States as possible.

Option II: Short Review Period

The intent of the short review period is to minimize the delay to OCS production caused by the formal separation of exploration and development. Under this option, the development plans would be provided to the Governors of affected states for comment within 90 days. No EIS would be prepared and no public hearings held. The request for states' comments within 90 days

may accelerate their notification of concurrence with the lessees certification that the development plan is consistent with approved coastal zone management programs. If State concurrence is not forthcoming, approval of the development plan and issuance would ^{probably} be delayed up to an additional 90 days.

Under this option, the size of the OCS area treated in the development plan and the plan's content would be determined by the lessee(s). The CZMA requires the lessee to provide "all necessary information and data" to the states in support of the certification of consistency with coastal zone management programs. This is likely to bring the lessee and the states into negotiation about the contents of the plan or its back-up data.

The short review period has the advantage of providing the states with the types of information now submitted to the Department, offering them an opportunity to comment, and minimizing the built-in delay. On the other hand, the position that no additional EIS is needed may be a target for litigation, especially for large initial developments in frontier areas. Such litigation could lead to substantial delays in development. Perhaps more importantly, delays from litigation are highly uncertain and make planning for initiation of construction difficult for industry.

Option III: Moderate Review Period

This option has been formulated to mesh with a maximum review period required under the consistency provisions of the CZMA, making use of the time provided to comply with the desires of the states for information and the requirements of the NEPA for Environmental Impact Statements on "major Federal actions significantly affecting the environment." Development plans submitted by lessees would be provided to Governors for comment within 180 days, the same period provided for their concurrence with the lessees certification of consistency. An EIS would be prepared only for those developments deemed major by the Department. Public hearings would be conducted at the discretion of the Secretary.

To allow for some integration of potentially separate developments by individual lessees, the Area Oil and Gas Supervisor would be given the authority to designate the area to be treated in development plans. Development plans would be required to include a description of onshore as well as offshore facilities and to provide environmental data on the sites chosen for major facilities. It may be that the site specific environmental data could be required at the time of site selection so that it could be considered by Federal and State agencies before completion of the designs needed for the development plan.

The advantage of the moderate review period is that it makes use of the time available if states decide to wait the full six months available under the CZMA. Since the states could delay approval of the development for six

months by withholding concurrence, the exchange of additional information and comments and the preparation of an EIS will not cause additional delay unless they take longer than six months. In order to minimize the time required to determine the necessity of preparing an EIS and performing the impact analysis, it would be helpful to have site specific environmental data prior to submission of the development plan.

Option IV: Extended Review Period

This option differs from the moderate review period in its requirement for an EIS and a public hearing for each development plan. In addition, the development plans would be required to include a projection of future developments for the region of interest to provide a context for evaluating the impacts of the cumulation of developments. Although the States comments and concurrence with certification of consistency with coastal zone mangement programs would still be required within 180 days, the EIS and public hearing requirements will frequently lead to longer delays before approval of development plans.

Although it is most similar to current congressional proposals, this option has the disadvantage of potential delay, not to mention added expense, in approving development plans both large and small. It would provide the States detailed information on all developments but would create a heavy workload for Federal, State and industry in documenting and reviewing that information.

III. Strategic Aspects

Three strategies warrant consideration in determining the Department's commitment to developing and implementing procedures to separate OCS exploration and development decisions:

1. retain the current procedure
2. develop and implement procedures in time for use in California sale in fall 1975
3. develop and implement procedures for use after the California sale

The Southern California sale, now scheduled for October 1975, provides a major decision point regarding the Department's policy because Governor Brown has made his approval and cooperation contingent, among other things, upon implementation of procedures to separate exploration and development. Early commitment to some form of separation is needed to gain cooperation in place of obstruction as well as to permit the actual implementation of new lease terms in the notice of sale.

Despite the pressures to implement a separation between exploration and development, the current procedures could, of course, be retained.

Development plans are now submitted to the Geological Survey for review before development permits are issued. Although these development plans are primarily technical and pertain to the design and operation of offshore facilities, there are indications that some oil companies are willing to supplement such plans with descriptions of the related onshore facilities of

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primary concern to the States. While a simultaneous review and informal coordination of State and local with Federal permitting decisions could result, there would be no general, formal procedures which specified the timing for exchange of information and assessments or the making of decisions.

The current procedure can result in delays if opponents to OCS development make use of the NEPA process, the courts, and State and local laws to obstruct leasing, exploration and development. Of course, these delays may not, in fact, occur or may be slight as the need for OCS oil mounts and negative impacts are viewed more realistically. Informal cooperation, as mentioned above, may also mitigate opposition, especially by State and local officials.

In contrast to the uncertain but potentially long delay and the difficulty of achieving coordination under current procedure, a formal separation of exploration and development will require a pause of specified length during which development plans are reviewed. A formal separation may also result in the requirement to prepare an Environmental Impact Statement and hold public hearings on each development plan. The writing and rewriting of an EIS can be quite time consuming, as well as costly.

An additional source of delay could result if it were necessary to postpone review until exploration was completed and development plans were prepared by a number of lessees. This could be necessary in order for State and local authorities to determine the aggregate impacts of separate but closely

related developments. While there are economic forces which tend to produce "unitized" development of an oil field as opposed to development spread out in time, the integration of related plans remains an issue to be resolved in developing separation procedures.

The key determinants in the decision to implement separation procedures before rather than after the Southern California sale are the gains to be expected from cooperation from the State of California as opposed to the work and time required to develop new lease terms and regulations. The Department has assured California that it would consider separation of exploration and development for the Southern California sale. If it is decided not to implement the necessary procedures by that time, good faith requires that California be notified. The result is not clear, but various legal and political means are available to delay and obstruct the sale.

On the other hand, it is clear that drafting new lease terms, developing criteria for writing environmental impact statements, and setting up the procedures with the States will require a full commitment within the Department to the resolution of the many issues of detail that are involved. It appears that this can be achieved by September in time for the California sale, but only with the full efforts and cooperation of all the offices with related responsibilities.



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UNITED STATES
DEPARTMENT OF THE INTERIOR
OFFICE OF THE SOLICITOR
WASHINGTON, D.C. 20240

NOV 6 1975

Memorandum

To: Deputy Solicitor

From: Associate Solicitor, Division of Energy & Resources

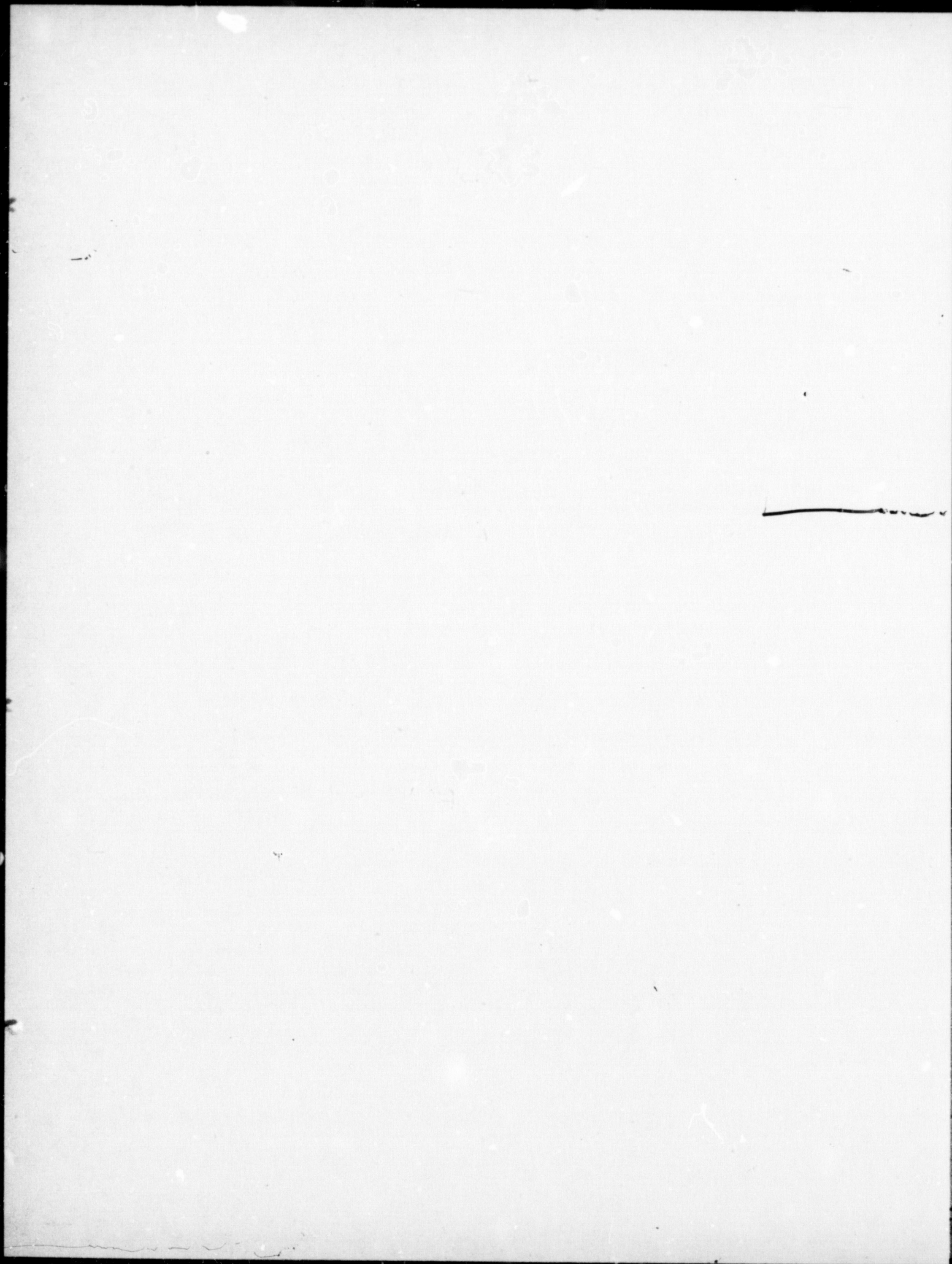
Subject: Cancellation clause in Outer Continental Shelf Lease

As you requested, we have reviewed the letter of October 3, 1975, from Mr. Preble Stolz, Director, Office of Planning and Research, State of California to Assistant Secretary Hughes. Mr. Stolz enclosed with his letter a legal memorandum of September 26, 1975, from Assistant Attorney General Shavelson of California, concerning "Proposed Outer Continental Shelf Regulations."

On March 10, 1975 we sent Assistant Secretary Hughes a memorandum on the subject "Making OCS Lease Production Rights Subject to Government Review" which discussed aspects of the problem about which Mr. Shavelson has written. A copy of our March 10 memorandum is enclosed for your information. In that memorandum I stated that "I do not believe that there is any means by which a provision which would bar the lessee from development forever could be justified". I took the position that the Secretary could issue a lease under which there might be an extensive period for review at the end of the exploration phase, but I stated that it would be necessary always that the suspension of that lease hold out the promise of some eventual development.

In coming to this conclusion, I relied on Union Oil Company v. Morton, 512 F.2d 743 (9th Cir. 1975). Mr. Shavelson has also relied heavily on that case in coming to a contrary conclusion. The Union case was not concerned with a lease which by its very terms provided that it might be cancelled at the end of the exploratory phase because of environmental considerations. Consequently, it is not precisely on point, though the reasoning in this case is applicable to this question. In my view the Union case does not support Mr. Shavelson's position, but rather mine.





I have had the Branch of Minerals prepare a research memorandum on this subject. That research memorandum concludes that (1) an OCS oil and gas lease must be issued for five years and as long thereafter as oil or gas may be produced from the area in paying quantities, and (2) an OCS oil and gas lease may be cancelled only upon the lessee's failure to comply with the provisions of the OCS Act, the regulations in force and effect at the time the lease is issued, and the lease itself, and not upon the occurrence of an event which does not involve the lessee's default. Provisions for the mandatory relinquishment or rescission of the lease upon the discovery of previously unknown environmental dangers are subject to essentially the same objections as a cancellation provision.

I concur in these views.

I wish to emphasize the importance of certainty in the terms of the OCS leases which we issue. Any attempt to include a provision for involuntary relinquishment or rescission or for cancellation upon some subsequent event would necessarily be based on such a doubtful and tenuous legal basis as to render the entire lease subject to attack. This would in my opinion be a deplorable result.

HUGH C. GARNER

Hugh C. Garner

cc:
DER RF
DER - Minerals
Mr. Ferguson

- FNFerguson:pat:10/31/75



2672

UNITED STATES
DEPARTMENT OF THE INTERIOR
OFFICE OF THE SOLICITOR
WASHINGTON, D.C. 20240

OCT 31 1975

Research Memorandum

From: Assistant Solicitor--Minerals
Division of Energy and Resources

Subject: Authority to terminate an OCS oil and
gas lease after the exploratory phase

Issue: Can the Secretary of the Interior provide in an OCS oil and gas lease or in a regulation in force and effect when the lease is issued that the lease may be cancelled at the end of the exploratory phase, or when some unexpected environmental hazard is discovered, even though the lessee has complied with all provisions of the OCS Act, the regulations in force and effect at the time when the lease is issued, and the lease itself? If the Secretary cannot include such a cancellation provision in a lease, is there some other method by which he can provide for the termination of the lease under those circumstances?

Facts: The Outer Continental Shelf Lands Act (OCS Act) (43 U.S.C. §§1331-1343) provides for the issuance of oil and gas leases. Section 8 (43 U.S.C. §1337) states in subsection (a) that the Secretary of the Interior may issue such leases, and in subsection (b) provides some of the provisions which must be included in such leases and gives the Secretary broad discretion with respect to other provisions. Section 5 (43 U.S.C. §1334) gives the Secretary extensive authority in the administration of leases.

Conclusion: An oil and gas lease under Section 8 must be issued for "a period of five years and as long thereafter as oil or gas may be produced in paying quantities," or certain operations are being conducted, and the lease cannot be cancelled during that period except when the lessee fails to comply with the OCS Act, the regulations in force and effect when the lease is issued, and the lease itself. Moreover, it is very unlikely that the Secretary could legally provide in a lease that it would be relinquished or rescinded in the event of the discovery of an unexpected environmental hazard. However, a



suspension of operations on a lease in the interest of conservation would probably be upheld where the suspension is to provide time for the development of new technology or the discovery of new knowledge to cope with unexpected environmental risks, and where the suspension will be terminated upon such development or such discovery.

Discussion: In the consideration of this question close attention was given to a memorandum of September 26, 1975, from Mr. J.L. Shavelson, Assistant Attorney General, State of California, on the subject "Proposed Outer Continental Shelf Regulations." Mr. Shavelson concluded that the OCS Act authorized the Secretary to provide that a lease would be subject to cancellation at the end of the exploratory phase, if environmental considerations warranted it. Mr. Shavelson believes that the Secretary may impose on lessees a cancellation (or some other form of termination) provision as long as it is included in regulations in force and effect at the time of lease issuance or in the lease itself and as long as the circumstances in which the power of cancellation (or termination) may be invoked are carefully defined by objective criteria and involve substantial and unacceptable environmental risks unknown at the time of the execution of the lease. If the Secretary has such authority under the OCS Act, he must, under Section 102(1) of the National Environmental Policy Act of 1969 (NEPA) (42 U.S.C. 4332(1)), exercise it in accordance with NEPA. In coming to the conclusion that the Secretary has this authority under the OCS Act Mr. Shavelson has relied heavily on Union Oil Co. of California v. Morton, 512 F.2d 743 (9th Cir. 1975). However, a careful examination of the OCS Act, and in particular of Sections 8(b)(2) and 5(b), reveals that Mr. Shavelson's interpretation is not justified, and that the Union case does not support his views.

The OCS Act gives the Secretary of the Interior broad discretion in the imposition of terms and conditions in oil and gas leases and in the issuance of regulations to carry out the purposes of the statute. However, this discretion is not unlimited. That there is a restriction on his discretion was recognized when the legislation was under consideration by the Congress. In the letter of May 26, 1953, from the Department of Justice to the Chairman of the Senate Committee on Interior and Insular Affairs, it was stated with respect to Section 8 that "...the practice of limiting the Secretary's discretion as to leasing procedure and lease provisions follows the precedent of the Mineral Leasing Act and is not objectionable." S. Rep. No. 411, 83d Cong., 1st Sess. 36 (1953). The Court of Appeals for the 9th Circuit recognized this restriction in the Union case, supra, when it stated on page 749: "Terms of the lease inconsistent with the statute are invalid."

Section 8 of the OCS Act (43 U.S.C. §1337) authorizes the Secretary to grant oil and gas leases. Subsection (a) establishes the method of issuing the leases and subsection (b) establishes the provisions of the leases. Subsection (b) contains four subdivisions. (b)(1) sets a limit on the size of a lease at 5,760 acres and (b)(3) requires a royalty of not less than 12 1/2 percent. (b)(2) provides that a lease shall "be for a period of five years and as long thereafter as oil or gas may be produced from the area in paying quantities" or certain operations are being performed. (b)(4) provides that the lease shall "contain such rental provisions and such other terms and conditions as the Secretary may prescribe at the time of offering the area for lease." It is subsection (b)(4) which gives the Secretary discretion in the establishment of lease terms, but that discretion does not allow him to disregard the explicit requirements of (b)(1), (2), and (3). This means that the Secretary cannot provide a different term for the lease than "five years and as long thereafter as oil or gas may be produced from the area in paying quantities."

Since the lease issued by the Secretary must provide for a term of five years and subsequent production, the next question is whether the Secretary can provide a means of cutting that period short upon some subsequent event, or, more specifically, by cancellation.

In the Union case, supra, the Court of Appeals concluded, on page 751, that "an open ended suspension of the right granted Union to install a platform would be a pro tanto cancellation of the lease." Such a suspension and hence cancellation would be beyond the Secretary's authority, in the view of the 9th Circuit.

Mr. Shavelson's memorandum takes the position that a cancellation would be legal if the regulations in force at the issuance of the lease or the lease itself provided for such a cancellation. In reaching this conclusion he relies on the Union case in which the 9th Circuit did say, on page 749, that "A lease may be terminated on its own terms in the event that stated conditions occur." However, this can only refer to "terms" which can be legally imposed on a lease, because the remainder of the same paragraph concludes that the terms of the lease must be consistent with the structure of the statute which authorizes it.

Cancellation is expressly provided in the OCS Act. Section 5(b) of the Act (43 U.S.C. §1334(b)) states when a lease may be cancelled. Section 5 provides that a lease may be cancelled, administratively under (b)(1) when it is nonproducing or by judicial action under (b)(2) when it is producing, whenever the owner of the lease "fails to comply with any of the provisions of this Act, or of the lease,

or of the regulations issued under this Act and in force and effect on the date of issuance of the lease. . . ." The owner of a non-producing lease must, under (b)(1), be given thirty days in which to correct the default. This is the only cancellation authority granted in the Act, and this authority is explicitly tied to non-compliance by a lessee. A lease cannot be cancelled unless a lessee fails to comply with a provision of the statute, the regulations in effect at lease issuance, or the lease itself. Only where a lessee commits such a default can the term explicitly granted by Section 8(b)(2), i.e., five years and as long thereafter as oil or gas may be produced, be cut short by Secretarial action. To hold otherwise it is necessary to disregard the express provisions of the OCS Act. Where environmental conditions are discovered which necessitate the termination of the lease the Secretary's recourse is to suspend operations in the interest of conservation while he seeks legislation to terminate the lease and to compensate the lessee. The Court of Appeals for the 9th Circuit in Gulf Oil Corporation v. Morton, 493 F.2d 141 (9th Cir. 1973), upheld a suspension of that type as validly issued, although in denying a rehearing in 1974 the Court revised its views to hold that the Secretary's authority to suspend operations on a lease while he sought termination legislation was limited; the Secretary could not indefinitely suspend operations for one Congressional session after another.

The provisions of Section 8(b)(2) establishing the length of a lease and those of Section 5(b) on cancellation, when read together, thus effectively answer the question whether the Secretary can provide in a lease that it will be cancelled if certain conditions exist, even though the lessee has complied with all applicable statutory, regulatory, and lease provisions. The Secretary's broad discretion in writing lease terms under Section 8(b)(4) is limited by these explicit provisions. Moreover, there are other provisions of the OCS Act which indicate that the position advanced by Mr. Shavelson cannot be adopted. Mr. Shavelson appears to wish the Department to issue a lease which will grant a lessee a right to explore for oil and gas, but which would give him no assured right to develop and produce oil and gas resources found in his explorations. ^{1/} Section 8 speaks simply of an "oil and gas lease"; it does not provide for an exploratory lease or a development and production lease. Section 8(a) states that the Secretary is

^{1/} It is assumed that, though Mr. Shavelson would deny the lessee absolute right to develop, the lessee would be the only one to whom a right of development could be granted by the Secretary at the conclusion of the exploratory phase.

to issue oil and gas leases "In order to meet the urgent need for further exploration and development of the oil and gas resources" of the OCS. This type of lease is thus to meet the need for both exploration and development, and there is not even a hint in the statute or the legislative history that under Section 8(a) the Secretary may issue one lease for only one of those purposes and another lease for the other purpose. Moreover, it should be noted that Section 8(b)(1) provides that the lease is to be for "a period of five years and as long thereafter as oil or gas may be produced from the area in paying quantities, or drilling or well reworking operations as approved by the Secretary are conducted thereon". The words used by Congress in this mandatory provision reveal that the oil and gas lease authorized in Section 8 is to be more than an exploratory lease. Otherwise there would not be a reference to production in paying quantities or to well reworking operations.

Because it is thus evident that the Secretary has no authority to include in a lease a provision for cancellation upon other ground than the lessee's noncompliance, the possibility of obtaining that result by some other means has been examined. One possible means would be to provide that the lessee will relinquish the lease upon the occurrence of a specific event such as the discovery of a hazardous environmental condition which was unknown at the time when the lease was issued. Another is to provide that the lease will be rescinded upon such an occurrence.

Both of these possibilities are rather transparent attempts to circumvent the restrictions on cancellation discussed above. The only real difference would be that the lessee would automatically lose his lease on the occurrence of the event, whereas, under the cancellation provision discussed above, the Secretary would have discretion as to whether he should cancel. Consequently, both of these methods would probably be inconsistent with the CCS Act to the same extent as the cancellation provision. Both have other difficulties as well.

Relinquishment carries an implication of a voluntary act. Section 5(a)(1) states that the Secretary may issue regulations to provide for relinquishment and he has done so in 43 CFR 3306.1. That regulation permits the lessee of his own volition to relinquish his lease upon meeting certain conditions. This is consistent with the usual meaning of "relinquish." To provide in the lease that the lessee

must relinquish the lease on certain conditions and thus shorten the term of his lease is quite inconsistent with Section 8(b)(2) and 5(b) of the OCS Act.

A provision that the lease will be rescinded upon a certain event presents other difficulties. The normal meaning of "rescind" is to "abrogate" or "annul". The general rule is that in rescission the parties must be returned to their circumstances prior to the issuance of the lease, although it is true that the parties may agree otherwise. 12 Williston, Contracts § 1454 (3d ed. 1970). Rescission is ordinarily a remedy for breach of contract. Williston, supra, § 1455. It is not written into a contract as an action which is to take place upon a certain event. In considering any provision for rescission (and the same is true for any mandatory relinquishment provision) the question of compensation for the lessee must be considered. Section 10 of the OCS Act (43 U.S.C. §1339) authorizes the refund of money under certain circumstances. These circumstances are very limited. It must be money which has been overpaid by the lessee. Certainly, there could be no payment of costs incurred by the lessee. Interest is specifically prohibited. Moreover, requests for refund must be made within two years of the overpayment. Otherwise special legislation will be required. Clearly, a satisfactory method of compensation cannot be provided under existing law. For all these reasons, no provision for mandatory relinquishment or rescission of the lease appears to be legally satisfactory under the OCS Act.

However, while any provision in a lease for its cancellation or its mandatory relinquishment or rescission upon a particular event appears impossible to sustain legally under the OCS Act, the Secretary does have broad authority to suspend operations under a lease where it is necessary to do so in the interest of conservation. This authority has been recognized in both the Union case, supra, and the Gulf case, supra. In Union the court said at page 751:

Factors 1 and 3, however, suggest conditions which the development of new technology or further study may lessen as threats to the environment. Further study of seismic risks in the Channel, or of the geology of the Dos Cuadros structure, for example, may produce evidence of environmental risks unanticipated at the time the lease was executed. Knowledge of these newly-discovered risks might induce Congress to cancel the lease. A suspension also might provide

time for an improved pollution technology to be developed. A suspension whose termination was conditioned on the occurrence of events or the discovery of new knowledge which can be anticipated within a reasonable period of time would be a valid exercise of the Secretary's regulatory power, and not a fifth amendment taking.

This quotation reveals the extent to which the Court of Appeals was prepared to go in the Union case in approving a suspension by the Secretary. A regulation (30 CFR 250.12(c)) now in effect spells out the Secretary's authority in the suspension of any operation "which in his judgment threatens immediate, serious, or irreparable harm or damage to. . .the environment. Such suspension shall continue until in his judgment the threat or danger has terminated." This is very broad authority and should suffice when environmental hazards not known at the time of lease issuance are discovered.

Fredrick N. Johnson

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MAY 16 1975

Memorandum

To: Environmental Assessment Team Leader, Atlantic OCS Office
From: Assistant Director, Minerals Management
Subject: Tract Selection Guidelines for the Proposed Mid-Atlantic OCS Sale #40

The basic requirements set forth in the August 19, 1971, OCS tract selection agreement are to be used in selecting tracts for the proposed Mid-Atlantic lease sale. The following specific information should be considered (by you and/or the CS Regional office as appropriate) in making tract selections for this sale and included in the joint report to the Washington offices of BLM and CS.

1. Nominations

The present system of analyzing weighted and unweighted nomination patterns should be used.

2. Geology

The following geological information should be considered in the joint tract selection procedure:

- A. Geologic information from coring (including fault interpretation and evaluation, etc.)
- B. Geophysical information from seismic data (used to determine faulting, define structures and stratigraphic conditions).

In executing your responsibility under the joint BLM/USGS tract Selection Agreement, you should obtain the best information possible on the nature and quantity of geologic and other technical data available to CS and the associated level of confidence in these data. This will help the decisionmaking concerning the relative weight of geologic information, industry interest and environmental, economic and special considerations. The following types of information should be reviewed:

72.2 P.F.

- a. What is the nature and extent of geologic and geophysical data which GS possesses in the proposed sale area?
- b. Can structures be defined in relation to specific tracts?
- c. What is the status of contracts for data collection to fill gaps in information prior to the target sale date?
- d. To what extent are the tracts considered for selection gas prone or oil prone?

In addition, you should attempt to obtain from GS the following information on oil and gas reserves in the sale area:

- a. Estimated total oil and gas reserves
- b. Estimates for production potential of oil and gas on both a tract-by-tract and prospect basis
- c. The probability of resource discovery on a prospect-by-prospect basis.

✓ The possession of this type of information would greatly facilitate the tract selection process. However, we recognize that time and manpower constraints may be a limitation.

3. Environmental Consideration

We believe you should continue the overall format of map overlays and environmental hazard zones in this tract selection. You should consider all pertinent environmental data available for the tract selection area. Include a summary of those environmental considerations in the supplement to the joint tract selection memorandum. Tracts or groups of tracts should be ranked for their potential environmental impact by relative suitability for leasing (not as 'suitable' or 'unsuitable'). Your initial ranking will assist in satisfying the requirements that summary ranking of tracts by potential environmental hazard must be included in the impact statements. Your ranking will, however, be subject to later changes as additional data such as GS primary potential production data, bearing testimony information, study findings, etc., is gathered.

4. Economic and Social Considerations

The following economic, social and institutional factors should be considered, where data is available, in the tract selection process and summarized in the supplement to the joint tract selection memorandum:

- A. The availability of refineries to process reserves found in this area.
- B. Pipeline requirements to bring products to shore.
- C. The availability of capital, manpower and equipment.
- D. The appropriate ratio of oil prone to gas prone tracts in view of projected energy needs.

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- E. Possible economic and social conflicts with existing activities of the adjacent communities.
- F. Impacts on State and local government revenues and land use requirements (i.e., property tax, land use plan, zoning regulations, etc.).
- G. Effect on area incomes by number and type of workers needed as a result of the sale and potential changes on population patterns or growth.
- H. Effects on ocean, rail, pipeline and highway transportation systems in the impact area.

3. Special Considerations

A. Size of Sale

The Mid-Atlantic area is important in attempting to reach the nation's energy self-sufficiency goal. In order to comply with Departmental policy, you should include the largest reasonable acreage considering industry nominations, environmental considerations, current technology, orderly development and other appropriate tract selection criteria. It is not mandatory to meet the initial 3.5 million acre goal previously discussed for this sale if criteria used in the selection process indicates fewer tracts would be desirable.

B. Deepwater Operations

The target area in this proposed lease sale is located seaward of a line which at no place is closer than 20 miles offshore and landward of a described line which approximates the 200 meter water depth contour. Any tract within the described area may be considered for selection regardless of water depth.

In your supplement to the joint memorandum recommending the selection of tracts under the above guidelines, you should include the rationale and a summary of data upon which your selection is based. Using the above criteria you should provide a first priority listing of tracts recommended for selection followed by a second and possibly a third priority listing for our use should the decision be made to offer the greatest amount of acreage feasible.

Since this will be the first tract selection by your office, plan for experienced help from other CCS field offices.

cc:
DDRF-D
720rf.
722 r.f.
Gul' OCS Office
Pacific OCS Office

Atlantic CCS
Alaska CCS
EER
Hansen:tjg:5/14/75
720, 722 hold

Dale Johnson

Deputy

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(722)

AUG 6 1975

Memorandum

To: Environmental Assessment Team Leader, Atlantic OCS Office
From: Assistant Director, Minerals Management
Subject: Tract Selection Guidelines for the Proposed North-Atlantic OCS Sale #42

The basic requirements set forth in the August 19, 1971, OCS tract selection agreement are to be used in selecting tracts for the proposed mid-Atlantic lease sale. The following specific information should be considered (by you and/or the GS Regional office as appropriate) in making tract selections for this sale and included in the joint report to the Washington offices of BLM and GS.

1. Nominations

The present system of analyzing weighted and unweighted nomination patterns should be used.

2. Geology

The opinion of the GS on the following geological information should be considered in the joint tract selection procedure:

- A. Geologic information from coring (including fault interpretation and evaluation, etc.)
- B. Geophysical information from seismic data (used to determine faulting, define structures and stratigraphic conditions.)

In executing your responsibility under the joint BLM/USGS tract selection agreement, you should obtain advice from the GS concerning the types of information and quantity of geologic and other technical data available to them and their associated level of confidence in these data. This will help the decisionmaking concerning the relative weight of geologic information, industry interest and environmental,

economic and special considerations. The following points should be discussed with GS:

- A. Can structures be defined in relation to specific tracts?
- B. What is the status of data collection to fill gaps in information prior to the target sale date?
- C. To what extent are the tracts considered for selection gas prone or oil prone?

In addition, you should attempt to obtain from GS estimates for production potential of oil and gas on both a tract-by-tract and prospect basis.

The possession of this type of information would greatly facilitate the tract selection process. However, we recognize that time and manpower constraints may be a limitation.

3. Environmental Considerations

You should consider all pertinent environmental data available for the tract selection area.

Tracts or groups of tracts should be ranked for their potential environmental impact by relative suitability for leasing (not as "suitable" or "unsuitable"). Your initial ranking will assist in satisfying the requirements that summary ranking of tracts by potential environmental hazard must be included in the impact statements. Your ranking will, however, be subject to later changes as additional data such as GS primary potential production data, hearing testimony information, study findings, etc., is gathered.

4. Economic and Social Considerations

The following economic, social and institutional factors should be considered, where data are available.

- A. The availability of refineries to process resources found in this area.
- B. Pipeline requirements to bring products to shore.
- C. The availability of capital, manpower and equipment.
- D. Possible economic and social conflicts with existing activities of the adjacent communities.

- E. Impacts on State and local government revenues and land use requirements (i.e., property tax, land use plan, zoning regulations, etc.).
- F. Effect on area incomes by number and type of workers needed as a result of the sale and potential changes on population patterns or growth.
- G. Effects on ocean, rail, pipeline and highway transportation systems in the impact area.

5. Special Considerations

A. Size of Sale

In order to comply with current Departmental policy, you should include in this tract selection for the North Atlantic the most reasonable acreage considering industry nominations, environmental information, current technology, orderly and timely development, GS opinion on potential of tracts and other appropriate tract selection criteria. Using the above criteria, you should provide; (1) a listing of tracts which you recommend as top acreage to lease, (2) a second listing of greater or smaller acreage of lesser quality but still of leasing interest, and (3) other listings as appropriate. If conditions are such that in your judgment, it is not logical to provide more than one listing, you should include in your recommendation, detailed rationale supporting your position. This will afford the Washington offices sufficient flexibility if necessary to alter the field recommendation. No significant adjustment in the joint recommendation will be made without your consultation.

B. Deepwater Operations

The target area in this proposed lease sale is located seaward of a line which is no place closer than 20 miles offshore and landward of a described line which approximates the 200 meter water depth contour. Any tract within the described area may be considered for selection regardless of water depth.

6. Participation and Coordination

A. NOAA

You should follow the procedures contained in I.M. No. 75-257 for coordination with NOAA in the tract selection process.

B: F&WS

Secretarial Order No. 2974 contains procedures and requirements for coordination with F&WS in the tract selection process. F&WS should be represented at your tract selection meeting and requested to have their formal comments prepared for attachment to the joint report.

C. State Representatives

Follow the procedures discussed at the OCS meetings held in the Washington office. The representatives should be invited to the initial meeting in which the environmental profiles are presented as well as to the tract selection meeting.

7. Supplement to the Joint Recommendation

In your supplement to the joint memorandum recommending the selection of tracts under the above guidelines, you should include the rationale and a summary of data upon which your selection is based. Summarize geologic, environmental and economic and social considerations in the supplement.

In addition to the tract selection map submitted, please include maps or overlays to the tract selection map showing major items affecting the tract selection area, e.g., ocean currents, endangered species, commercial and sports fishing areas, critical habitat areas and migration routes, cultural or archeological features, ocean dump sites, telephone cables, fairways, coral reefs, etc. This type of visual information is required for our briefing meetings for Bureau and Departmental officials.

/s/ Frank A. Edwards

cc: DDRF-D
720 RF
722 RF
Gulf OCS Office
Pacific OCS Office
Alaska OCS Office
Atlantic OCS Office
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OCS TRACT SELECTION FOR GENERAL OIL AND GAS LEASE SALES (GS — BLM)

I. The Tract Selection Process

A. Introduction. The tract selection process is critical to an orderly leasing program. It is the second of three stages in the mineral resource identification phase of the pre-leasing process. The three stages are: (1) tentative schedule, (2) tract selection and (3) pre-sale evaluation.

(1) Tentative schedule. This is development and updating of the Department's tentative OCS leasing schedule. In this stage general sale areas are identified and tentative acreage figures for each sale are developed, based on broad resource knowledge, which are intended to provide for orderly development of OCS resources and to maintain the proper contribution of OCS production to the national supply.

(2) Tract selection. In the tract selection process, the Department gathers and reviews more detailed geophysical, geological, engineering and economic resource information on areas proposed for sale. Based on this review, a more refined estimate of the potential supply of hydrocarbons is made. The size of the sale (in acreage) is modified as necessary, to maintain as adequate a rate of production as possible to meet the demand for these resources.

(3) Pre-sale evaluation. In the pre-sale evaluation process the final and most refined resource estimates are developed and provided for use in the actual decision whether to accept or reject individual high bids.

This refined information is then also fed back into the next revision of the five-year tentative schedule to ensure that new sales are projected on the basis of the best information available.

B. Policy Statements.

(1) Supply — demand. The overriding factor in OCS leasing is to strive for a supply of oil and natural gas adequate to meet the demand for these resources. This is the foundation of and justification for the existence of the leasing program. The acreage selection process must consider the need to balance supply with demand.

(2) Sale size. Acreage is selected in sufficient amounts to engender industry interest and promote a fair market value return. As a general rule the range of sale size is to be 300,000-600,000 acres.

(3) Tracts. The general rule is to select (a) drainage tracts, and then a mixture of (b) tracts in moderately developed areas, and (c) rank wildcat tracts. Drainage tracts have the highest priority. Single nomination tracts are not inflexibly excluded if other criteria indicate their inclusion to be beneficial to Department management objectives.

(4) Environment. The environmental implication of all tracts that are selected for leasing consideration is preliminarily reviewed and analyzed at this stage. After tracts are selected, detailed environmental analyses of the tracts are made, environmental impact statements are prepared and public hearings held.

II. General Responsibilities.

A. Washington Offices. The responsibility of the Washington Offices is to reflect Departmental objectives as specific guidelines which can be used in the actual tract selection process. These guidelines must flow from the Department's leasing objectives^{1/} of (a) orderly and timely resource development, (b) protection of the marine environment, and (c) the receipt of fair market value for leased marine resources. The guidelines provide general direction to the field offices, which are, in turn, responsible for the selection of individual tracts. The tract selections will be reviewed to ensure

^{1/} The Department's leasing objectives are based on legislative mandate. (a) Orderly Resource Development — Based on the OCS Lands Act of 1953 which states that the Secretary is authorized, in order to meet the urgent need for further exploration and development on the OCS, to grant to the highest responsible qualified bidder by competitive bidding oil and gas leases on the submerged lands of the OCS. (b) Protection of the Marine Environment — Based on the National Environmental Policy Act of 1969 which states that all agencies of the Federal Government shall utilize a systematic, interdisciplinary approach which will ensure the integrated use of the natural and social sciences and the environmental design arts in planning and decision making which may have an impact on man's environment. (c) Receipt of fair market value for leased marine resources — Based on USC 31, Sec. 483 (a) which obligates the Federal Government to obtain a fair return for public lands sold or leased. This concept has been further implemented within the Executive Branch of the Government by BOB Circular A-25.

conformity with Departmental program objectives and current policy. The initial tract selections may be modified as necessary in order to ensure such conformity.

The Washington Offices will be responsible for furnishing to the respective field offices guidelines such as, but not limited to:

1. Recommended size of sale.
2. Tracts or Areas for Special Consideration.
3. Information relative to Administration or Department policy.

B. Field Offices.

(1) BLM. This office is responsible for furnishing the historical and current leasing status of all tracts selected and their locations within fairways, anchorage areas, warning areas, and proximity to pipelines.

(2) G. S. This office will be responsible for furnishing technical information, including geological, geophysical, engineering and paleontological information in the determination of tracts to be recommended for selection.

III. Procedures

A. Field Offices.

(1) BLM. This office will make a preliminary identification of tracts based upon the following criteria.

(a) Total number of weighted and non-weighted nominations per tract.

(b) Need to initiate leasing of tracts in rank wildcat areas in terms of industry interest and development capability, competition, and the timely future availability of resources to the consumer.

(c) Tract history.

(d) Nomination patterns.

(e) Mix of tracts by

(1) water depths

(2) distance from shore

(3) nominators

(f) Through analysis of past environmental statements, the BLM field office will identify tracts selected that have been deleted from past sales or tracts for which special environmental stipulations were developed.

(2) G. S. This office will make a preliminary identification of tracts based upon the following criteria:

(a) Need to initiate leasing in rank wildcat areas in a manner that will help ensure proper consideration of development of geologic structures and trends.

(b) Drainage tracts or those in imminent danger of drainage.

(c) Tracts requested by companies who have presented data for G. S. inspection and evaluation, demonstrating the necessity and desirability of these tracts for further development.

(d) Tracts which are most prospective for production.

(e) Other tracts susceptible to prompt drilling and development.

(3) Joint BLM-GS

(a) BLM, having completed its analysis under A. 1 above, will as soon as practicable (not to exceed 10 work days after end of nomination period), present to GS a list of tracts, and a map with the tracts depicted thereon, ranked in order of leasing preference.

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(b) G.S. will compare the list as soon as practicable (within 10 work days after receipt from BLM) with the data assembled under A. 2 above, for concurrence or non-concurrence.

(c) Immediately following the G. S. analysis representatives of the offices will meet to make a joint review of all tracts identified and to prepare the final recommendations to the Washington offices.

(d) A joint report will be made to the Chief, Division of Minerals, BLM, and to the Chief, Conservation Division, G.S., submitting the field office recommendation within 5 work days from the meeting mentioned in A. 3 (c) of this section. The field office joint report will contain sufficient tracts, ranked in order of priority, to meet the sale size initially established by the Washington office. The joint report will identify any variations between the respective field office recommendations and the reasons therefor. The joint report will provide, for each recommended tract, the information identified in A. 1 and 2 of this section. In addition, to aid in the supply analysis projection and the final sale size determination, the GS will provide a preliminary resource estimate (total barrels or MCF per acre) for each tract based upon the drainage estimate or the average for the trend in which the tract is located.

B. Washington Office. Upon receipt of the joint tract report from the field offices, BLM and GS staff shall meet to review the recommendations in relation to the tract selection guidelines and any late arising policy guidance. Within ten working days of receipt of the field offices joint report, the BLM-GS staff will either (1) agree upon the tract selections, or (2) identify those tracts not agreed upon and the reasons therefor, and (3) forward for final action a list of agreed upon selected tracts and, where necessary, a list of tracts not agreed upon and the basis therefor.

Approved:

MONTE CANFIELD, JR.

Chief, Division of Minerals, BLM

BURT SILCOCK

Director, BLM

Date 27 Aug. 1971

Approved:

RUSSELL G. WAYLAND

Chief, Conservation Division, GS

W. A. RADLINSKI

Acting Director, GS

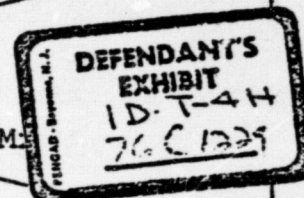
Date 27 Aug. 1971

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Charles Marciante?

Then, the next witness will be Mr.

John Brown.



Steven Levy?

MR. LEVY: Gentlemen, I'm testifying as a member of the New Jersey State Beach Erosion Control Commission on the potential effects that OCS activity might have on our shoreline of New Jersey.

The New Jersey State Beach Erosion Commission was established under State Statute in 1948. According to the Act, the Commission, consisting of four State Senators, four Assemblymen and four members at large are charged to "investigate and study the subject of the protection and preservation of beaches and shorefront of the State from erosion and other damage from the elements, to effectuate such protection and preservation of the said beaches and shorefront, and other purposes incidental thereto."

Plans exist to expend \$140 million in shoreline protection along the New Jersey coast with the Federal government picking up \$62 million of the total cost. Some of the Federal funding has already been authorized by Congress while the rest of the amount has been requested and awaiting Congressional action.

The Beach Erosion Commission has recommended

1 spending about \$30 million over the next five years
2 toward the reclamation of our coastline. This sum
3 includes funds toward the construction of the projects
4 mentioned above, a full environmental design study for
5 the coast, inland waterway and channel reparation assess-
6 ment, riparian tidelines delineation and more important
7 to you, the study to minimize the impact of offshore oil
8 on the coast.

9 With respect to a description of the
10 New Jersey coastline, one could think of the shoreline as
11 being geographically divided into four sectors.

12 At the extreme north to Sandy Hook, the
13 coastline is sheltered by bays and inlets, protected
14 somewhat from the open sea. This region has undergone
15 extensive industrial development and this is the region
16 where the northern New Jersey petrochemical industry is
17 concentrated.

18 South of Sandy Hook, to just below Point
19 Pleasant, the coastline is fragile, exposed to the severe
20 forces of the Atlantic. Here the shore is being stabilized
21 by artificial means--jetties and extensive seawalls.

22 Below Point Pleasant to the tip of Cape May,
23 the coastline is sheltered by barrier beaches and dunes.
24 Here nature has provided the coastline with an effective
25 but environmentally sensitive buffer.

1 Rounding Cape May to the upper reaches of
2 the Delaware Bay, location of our other refinery area,
3 the shoreline is buffered by the sheltering effect of the
4 protected bay.

5 The major impact Offshore Oil activity will
6 have on the New Jersey shoreline will be the location of
7 the oil and gas pipelines that will cross this boundary.
8 It is difficult at this stage in the accelerated leasing
9 plan to adopt proper protective measures to insure the
10 continued viability of our State's entire coastal
11 boundary. Any protective measures which, of necessity,
12 thus will be imposed, must take into account the disparity
13 in the character of one section of the coast to the next.
14 For example, the problems of where the pipe comes ashore
15 in Raritan Bay or in Delaware Bay is less severe a
16 problem than if the pipe were to come aground in the
17 Harvey Ceders or Wildwood area.

18 The major bays in New Jersey can be
19 characterized as shallow, sandy bottomed, relatively
20 stable bodies of water. Pipe groundings in the bays do
21 not present as much a danger as those coming across
22 unprotected shoreline.

23 The pipelines, whether oil or gas, will
24 still have to be buried, but the safeguards in laying the
25 pipe are not as severe. If the pipe were to come ashore

1 in Monmouth County from Sandy Hook South, the need for
2 safeguards increases. The near-shore bottom in Northern
3 Monmouth undulates which makes laying pipeline extremely
4 difficult, if not impossible. The degree of shoreline
5 bottom undulation lessens as you go south toward Point
6 Pleasant. About eight miles north of Point Pleasant
7 seems to be, what we hear to be, the best location. That
8 is, according to some of the newspaper reports of oil
9 interests in that area.

10 The relatively low shore bottom relief in
11 the Point Pleasant area is subject to change, however,
12 during periods of severe weather. Pipe burial will have
13 to extend onshore at least 75 to 100 feet before surfacing
14 in order to accommodate shifts in the beach line.

15 South of Point Pleasant, pipe crossings of
16 the beach ridges and dunes is a different situation. In
17 this region of our coast, the waterline can shift as much
18 as 50 feet inland due to severe coastal storms. These
19 same storms can alter the near shore bottom by as much as
20 between 20 to 30 feet as it did in 1964.

21 Land disturbance in the Harvey Cedars area,
22 the barrier beach areas, resulted in breeches of the
23 barrier beach in 1948 and again in 1966. The inland areas
24 adjacent to the breeching experienced heavy damage. Had
25 the land disturbance been rectified, the chances are the

1 breeching would not have occurred.

2 The point is, pipe crossings of barrier
3 beaches is a major engineering problem. As a bare minimum,
4 the pipe should be deeply buried, and should not be
5 resurfaced for at least 100 feet from the waterline. The
6 beach must be restored with the excavated sand or sand of
7 the same particle size to minimize erosion. Once the
8 sand has been replaced, the local grasses must be planted
9 and allowed to establish.

10 Unless these precautions are taken, the
11 potential for pipeline damage and breeching of the barrier
12 beaches is real.

13 I would suggest to the oil companies, State
14 and Federal agencies, that they review the histories of
15 sewer plant outfall lines that are situated along our coast.
16 This should have been included in the Environmental Impact
17 Statement, but, unfortunately, was not. Perhaps their
18 experiences might be some help in determining the require-
19 ments of oil and gas pipeline emplacements along the
20 New Jersey shoreline.

21 These statements seem to indicate that the
22 Shore Protection, or the Beach Erosion Commission is
23 considering the actualities of the proposed advance. This
24 is not so. We have taken no official position with this
25 regard. This testimony is in the potential that such pipe

1 crossings will occur.

2 Thank you, gentlemen.

3 MR. ROBISON: One question.

4 MR. LEVY: Yes, sir.

5 MR. ROBISON: I take it that it's your
6 opinion that pipelines can be brought ashore under
7 appropriate circumstances with proper regulation?

8 MR. LEVY: Yes, sir.

9 MR. ROBISON: Does not the State of New
10 Jersey, in your judgment, have sufficient authority to
11 issue the appropriate regulations and to oversee the
12 pipeline construction, location, type, etc., so that your
13 concerns can be satisfied?

14 MR. LEVY: Well, we have to break it up
15 because of the difference in the legal aspects between oil
16 and natural gas pipelines. As I understand, with natural
17 gas pipelines, once a certificate is issued, the company
18 has jurisdiction--the State has no jurisdiction of where
19 the pipe comes ashore. They have the right of eminent
20 domain. So the State has no protection in that regard.

21 With regard to oil pipelines, yes we do
22 have some protection and we do have the "Capra" Act,
23 Coastal Act. But, in New Jersey, the coastal zone as
24 defined by the State, can be as little as 1,000 feet wide
25 and, therefore, does not allow for proper protection just

1 inland of that little zone. So that, at least in my
2 opinion, we're not in the position to deal with the impact
3 of a major find off the coast of New Jersey.

4 MR. ROBISON: But, the State of New Jersey
5 could proceed through legislature and other bodies to
6 address this problem, I would think.

7 MR. LEVY: Yes, but, as you know, legislation
8 takes time to formulate and to implement. And, if the
9 major find were located, it would take us some time to
10 rectify and to plan for these events. Right now, we just
11 don't know where to look as to where the possible impacts
12 are to occur. And, because of the diverse nature of the
13 New Jersey shoreline, it is very difficult at this time,
14 to establish legislation that could treat these individual
15 areas in any general form. Right now, we would be shooting
16 in the dark. We just can't.

17 MR. ROBISON: Well, this obviously points up
18 the need for further cooperation among the State, the
19 Federal people, and the oil companies.

20 MR. LEVY: Absolutely. Absolutely, sir.

21 MR. ROBISON: Thank you.

22 JUDGE MOORE: Thank you, sir.

23 Senator Buehler?

24 SENATOR BUEHLER: I'm apologizing for being
25 late -- coming down, the fog on the Garden State Parkway

1 America be in a better economical position to "Put
2 American Back To Work."

3 Thank you.

4 JUDGE MOORE: Any questions?

5 Thank you, sir.

6 I'll call again on Diane Graves. Is she
7 here?

8 I presume not. I'll call again on
9 Mr. Zedrosser.. I see no one coming.

10 So, Mr. Jarmer. Elwood Jarmer.

11 Go ahead, Mr. Jarmer.

12 MR. JARMER: Mr. Chairman. My name is
13 Elwood Jarmer. I am the Director of the Cape May County
14 Planning Board. With me today is a member of our Planning
15 Board, Mr. Fred Long and a member of my staff, Mr. Robert
16 Myers. We thank you for the opportunity of appearing
17 before your committee to present our statement. This
18 statement is the official policy of the Cape May County
19 Board, elected governing body of the County, the County
20 Planning Board and the Cape May County Environmental
21 Council. I will submit copies of the Freeholders and
22 Planning Board resolutions and a full copy of this state-
23 ment after my presentation. For purposes of time, I'm
24 not going to read the whole thing, but try to paraphrase
25 certain sections.

DEFENDANT'S
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1 story here. We are talking price.

2 Now, domestic production also, I think we
3 need to look at the distinction between costs and prices.
4 In the case of domestic production, part of the costs are
5 transfer payment, lease bonuses, profits taxes, taxes paid
6 to the localities.

7 So, I think we need to look at the net ef-
8 fect as to how the U.S. society in total, and that I would
9 contend that domestic costs of oil would be cheaper.

10 MR. WHEELER: But not to the consumer at
11 the gasoline pump?

12 MR. YOUNG: That would be correct. The
13 consumer wouldn't necessarily have the benefit of this ex-
14 cept indirectly through taxes that are paid to governmental
15 bodies which in turn would reduce taxes paid by the con-
16 sumer, through other means. So, I would say the consumer
17 is benefitted indirectly but probably not directly at the
18 price.

19 This is assuming, of course, a free market
20 instead of price controls like we presently have.

21 JUDGE MOORE: Mr. Steve Gordon? Mr.
22 Charles Worthington?

23 CHARLES WORTHINGTON: Good morning. Mr.
24 Chairman, my name is Charles D. Worthington, I'm the County
25 Executive of this great county of Atlantic. And, we, of

Atlantic County, as have other Americans, have become increasingly cognizant of the energy dependence of our country.

Since October 1973, when the Arab petroleum exporting countries reduced crude oil production, imposed an embargo on the shipment of crude oil to our country, and then raised the price of crude oil in a series of large steps, the "Energy Crisis" has become the shibboleth of our day.

Who can forget the long lines of automobiles waiting to purchase a limited number of gallons of gasoline, gasless Sundays, the heating oil shortages, truckers' protests, and declining auto sales which all emphasized our economy's dependence on energy? This crisis was a clear demonstration of our vulnerability to the actions of oil exporting countries and of the dangers of our dependence on imported petroleum.

The energy crisis has given rise to an awareness that something is critically wrong, when an ostensibly healthy economy suddenly breaks down -- leaving people without heat, the use of their automobiles, or without their paychecks.

There have been several responses to the energy crisis. The two most prominent are the proposals for the conservation of energy and the proposals for the expansion of energy supplies. The conservationist position is established on the presumption that wasteful energy

practices are caused by mistakes that can be rectified by public policy.

The expansionist policy does not question energy usage, but tries to provide the energy which will meet whatever the market demands. It is pursuit of this expansionist policy which will be undertaken through the O.C.S. Sale Number 40, that we meet today in public session to discuss.

The outcome of these proceedings will be the final determinations regarding not only where, but the procedures how the exploitation of the Atlantic O.C.S. for oil and gas will occur.

I am deeply concerned with the proposed action which would cause leasing, drilling and development of the Atlantic Outer Continental Shelf and the impact that these actions would have on the mainland, coastal and marine environment of Atlantic County and the State of New Jersey.

The fate which awaits Atlantic County and the State of New Jersey must be designed in such a fashion as to further enhance all economic, social and environmental sectors, which, when orchestrated in combination, create our quality of life.

To aid in the assurance that all precautions have been, and most importantly, will continue to be

pursued, I submit the following set of recommendations:

1. Liability and Compensation. Even with the best technological safeguards, some O.C.S. accidents are inevitable. "Near shore spills resulting from pipeline or tanker accidents pose the highest threat".

"Heavily contaminated beaches will remain unsuitable for recreation so long as they remain coated with oil."

The Federal Government should carefully consider the full economic environmental implications of various types of liability - fault or no fault - and various means of ensuring adequate compensation such as liability insurance for operators or a revolving fund financed through charges on operators.

To this end, I support the speedy acceptance and passage of H.R. 10756 "The Federal Oil Pollution Liability and Compensation Act of 1975 which is now before the House Committee on Public Works and Transportation and Merchant Marine and Fisheries.

2. Anticipated Pipeline Corridors.

The County of Atlantic will vigorously oppose any pipeline corridor which is proposed to be located within the Great Egg Harbor River Estuary or the Mullica River Estuary.

The County of Atlantic will vigorously oppose a pipeline corridor which is located within a major bay.

Atlantic County will vigorously oppose a pipeline corridor which would cause substantial dune destruction.

"Tanker off-loading to barges in estuaries or bay is not anticipated" by the EIS. If at any time this proposal is submitted for off-loading in the bays and/or estuaries of Atlantic County, we will oppose it.

3. Visual Pollution.

Due to the tourism generated by Atlantic County's marine environment, we recommend that a line be drawn which would keep all exploratory and developmental equipment below the horizon-sight of view from all hotel rooms.

4. Off-Shore Oil Revenue Sharing.

There is presently no equivalent sharing of revenues from Federal OCS activities as the 37.5 percent shared from mining operations on Federal lands within state boundaries. It is my contention that some of the revenues collected by the Federal Government from OCS activities need to be shared with contiguous coastal jurisdictions to compensate these areas for services provided to off-shore operators, and encourage these areas to provide for the orderly development of the O.C.S.

The development of petroleum resources from OCS regions produces both economic benefits and costs for

adjacent coastal areas. One of the major benefits is increased employment and associated incomes for people in the region, while the primary cost of such development stems from increased demand for governmental facilities and services.

The development of these petroleum resources is of particular concern because the activity is beyond the taxing authority of both state and local governments. Although corporations engaged in OCS activity must pay bonuses and royalties to the Federal government, these benefits are not automatically shared with the state where the demand for state and local governmental services occur. As a result, the increased demand for governmental facilities and service from local governments is made more severe by the inability to reach all of those responsible for the increased cost.

5. Separation of Exploration Leases from Development Leases.

The separation of these two phases of OCS mineral recovery would further enhance the Department of Interior's leasing objectives for the following reasons:

a. Precision of Estimates.

While reading through many documents concerning energy outlooks and future supply, I was amazed to discover the plethora of estimates of reserves.

1 Since the bids will be based upon the prob-
2 able amount of recoverable reserves and there appears to be
3 a body of literature attesting to rather diverse estimates
4 of these reserves, it only seems logical that the first
5 question to be answered is - just how much oil and gas is
6 there?

7 The most incredible thing is that not only
8 is someone willing to sell something which they don't know
9 the value of, but there appear to be so many willing to
10 buy it.

11 In testimony before the Senate Committee in
12 Interior and Insular Affairs in connection with the over-
13 sight hearings on the Outer Continental Shelf Lands Act, in
14 April 1972, the American Petroleum Institute responded to
15 Question D.2, "Using such information, to what extent can
16 the most promising acreage be identified, and with what
17 degree of confidence can recoverable petroleum reserves be
18 estimated prior to drilling?" The answer: "Where no fields
19 have been discovered, estimation of the petroleum potential
20 of any geologic province or sale area is a particularly
21 speculative undertaking."

22 So it would appear that if through the
23 exploratory phase a final estimate was reached, we would
24 be able to assess a fair market value which would be bene-
25

1 not be subject to paying too much for too little, and the
2 American people would be assured of not getting too little
3 for too much.

4 b. Protection of the Environment.

5 When a final estimate can be agreed upon,
6 then it is most plausible and highly probable that the
7 assessment of Environmental Impacts, both off-shore and
8 on-shore, can be qualified and quantified, since there does
9 exist a high correlation between the amount of product and
10 the commensurate amount of Capital, Labor and Land to
11 fully develop the resources. It would allow Environmental
12 Impact Statements to make statements rather than carefully
13 worded, seemingly declarative sentences which usually have
14 a disclaimer within them preceded by should or might or
15 maybe.

16 In summation I would like to say that we are
17 all now acting in the role of caretaker. What we decide
18 today may change Atlantic County, if not the entire New
19 Jersey coast, for many years to come. What we decide today,
20 will become the inheritance of those who come after us.
21 What we actually leave behind, rather than what we tried to
22 accomplish, will be a far greater statement of what we were.

23 The American writer, Carl Sandburg is brought
24 to mind. He once wrote of a fog. The fog comes in on
25

1 on silent paunches and then moves on. We who live in
2 coastal environments are very familiar with this natural
3 phenomena. The fog is perceived as an intrusion upon the
4 built-form and overtime adequate safeguards and rules have
5 been developed which allow the built-form to continue to
6 co-exist with it. It is only when the safe-guards are
7 ill-prepared and the rules ignored that the built-form
8 finds itself engulfed in tragedy. Sandburg began his
9 poem with the lines "The fog comes in" and then he ends
10 it with "And then it moves on." We, who live along the
11 coast, can tell when a fog is building; but we can only
12 hope that there is no tragedy left behind when it moves on.

13 Thank you.

14 MR. ROBISON: Mr. Worthington, your state-
15 ment is a thoughtful one and I think helpful to us and we
16 appreciate your being here. Let me ask you two or three
17 questions that I think are appropriate because of the posi-
18 tion you occupy as executive for the County.

19 I take it that although you would be opposed
20 to pipelines coming ashore in the County in certain speci-
21 fic areas and you enumerated those areas, that you would
22 not necessarily be opposed to pipelines coming ashore in
23 other areas under appropriate regulations?

24 MR. WORTHINGTON: That's correct, Mr. Robison.
25 I feel that built up areas certainly should be avoided and

1 I feel that the river escuaries that are so vital to the
2 natural habitat and to our environment, certainly should
3 be protected from the potential of damage from spills.

4 MR. ROBISON: Under the authorities that
5 you operate, do you feel that you've got adequate authori-
6 ty under the law or that's granted to you under your char-
7 ter, whatever, to regulate pipeline construction and loca-
8 tion of pipelines and this type of thing?

9 MR. WORTHINGTON: I don't really feel that
10 we have. Perhaps on the State level through the CAFRA Act,
11 we do, but then we in the county feel that we don't have
12 the kind of impact or input on the state level that perhaps
13 we ought to have.

14 MR. ROBISON: Are you working on that?

15 MR. WORTHINGTON: Are we working on it?

16 MR. ROBISON: Yes, are you trying to get
17 more authority if you think you need it?

18 MR. WORTHINGTON: We are working with the
19 Department of Environmental Protection in that we have
20 made them very much aware of our concerns. But, insofar
21 as a legal determination, the state is very reluctant to
22 give up what it feels are its prerogatives to county govern-
23 ment. So, insofar as Environmental Protection is concerned,
24 what we are trying to do is petition through the state and
25 we also frankly feel that the state itself may not have

1 the adequate powers to protect. So we are somewhat appre-
2 hensive.

3 MR. ROBISON: Okay, I am developing this
4 dialog because I think very strongly that the local people
5 and the states have a strong role to play in how these
6 developments will take place or should take place. I
7 think through your Coastal Zone Management Acts, through
8 your zoning authority, through these types of things that
9 you should have some kind of considerable impact on the
10 way the development unfolds.

11 Aside from the question of whether the govern-
12 ment and the nation as a whole gets a fair return on the
13 leases, does it really make any difference to you and your
14 people in this area, whether we go ahead with the lease
15 sale before or after we know how much oil is out there?

16 MR. WORTHINGTON: Well, I think I have out-
17 lined the way that I prefer.

18 MR. ROBISON: But the impact isn't going to
19 be any different on the county, is it?

20 MR. WORTHINGTON: I'm not sure that it is.
21 If I had my way I would like to know what we had there be-
22 fore we get into a position to sell it.

23 MR. ROBISON: But, if we sell it and the
24 companies go out there and find there isn't any oil, there
25 is very little impact on the county, right?

1 If they find that there is some there is
2 going to be impact, but there would be that impact anyway.

3 MR. WORTHINGTON: I think it is a bad busi-
4 ness procedure on both sides. As I indicated here, it
5 seems incredible to me that we're selling something that
6 we don't know what we are selling and there are an awful
7 lot of people who are willing to buy, you know, propoertedly
8 they don't know what they are buying.

9 MR. ROBISON: Well, I appreciate that and I
10 qualify my statement in that regard.

11 MR. WORTHINGTON: Well, it makes a difference
12 to me as a citizen in that I think the best way to do busi-
13 ness is to do it fairly and justly and honestly and to get
14 the best return for the people. And I don't really think
15 that perhaps we are looking to get the best kind of return.
16 If we knew what was out there before we sold these leases,
17 I think we would be in a much better position to bargain for
18 a better price.

19 MR. ROBISON: I understand that point of
20 view. Now, in testimony yesterday from Senator Buehler,
21 where he indicated he would be opposed to any type of acti-
22 vity out in the OCS, at least at this time, and he was very
23 much opposed to bringing pipelines ashore and the building
24 up of any intrastructure in the county in the area, is that
25 your position also?

1 MR. WORTHINGTON: No, that's not my position.
2 I feel that if there is oil out there, and I suspect very
3 much that there is, that it is going to be developed. I
4 think it's in the national interest to develop it. I'm not
5 concerned about that. I'm concerned about the interest of
6 the state and the interest of the county in protecting what
7 we have here now. And, to make sure that what is developed
8 is developed in a way that is compatible with our existing
9 economy, with our existing major resort industry and with
10 our existing beautiful environment.

11 MR. ROBISON: What about a tank farm? Do
12 you think the county could accommodate a tank farm and
13 still maintain its tourist industry?

14 MR. WORTHINGTON: I'm not sure of that at
15 all. I've got some serious reservations but I'm open.

16 MR. ROBISON: Thank you, very much.

17 MR. WORTHINGTON: Thank you, Mr. Robison.

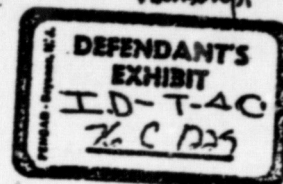
18 JUDGE MOORE: Mr. Worthington, thank you.

19 MR. WORTHINGTON: Thank you, Mr. Chairman.

20 JUDGE MOORE: The next witness will be the
21 mayor of the City of Wildwood, the Honorable Guy Muziani?
22 Is Mayor Muziani here? All right, next will be the Mayor
23 of Camden, New Jersey, the Honorable Angelo Errichetti.

24 MR. ANGELO ERRICHETTI: Good morning. I

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HON. JOSEPH F. BRADWAY, JR.: Thank you.

I have a prepared text and after delivery of the text, I would like to add some comments and needless to say, hopefully, there are some questions that I might answer.

For the Mayor of New Jersey's largest resort to be in favor of outer Continental Shelf oil exploration and drilling has appeared to many to be incompatible ideals. I have tried to be objective in my analysis of the economic benefits as well as the potential hazards to the resort economy should a spill occur. I have tried to assess the local effect with an eye toward the national needs.

The nation as a whole, the state in general and Atlantic City in particular have definite needs and desires to bolster their respective economies. I am concerned with the unemployment that exists throughout the country. I am further concerned that no sensible reversal of this unemployment can be accomplished without industry and commerce, and I ask how can the wheels of commerce turn if there be no energy to generate that motion.

Development of the OCS has been delayed longer than it should have been. The best interests of the national economy and the American public at large

1
2 are not being properly served with any further delay.

3 ... It is incumbent upon the leaders of this
4 nation to maintain America's commercial viability. It
5 is likewise up to them to be mindful of the balance of
6 trade relationship that is advantageous.

7 It is their responsibility to safeguard
8 the national defense of this country with a minimum of
9 dependence on international imports.

10 I fervently feel that some legislative
11 and/or administrative demands imposed upon the success-
12 ful bidders may make the leasehold sales now, and in
13 the future, more acceptable to state and local govern-
14 ments and the general public. Some of these that might
15 be considered are:

16 1. No rigs within 35 miles of resort areas.

17 2. At least 30 per cent of the production
18 contiguous to that state be used in that state, or at
19 least offered to that state.

20 3. Not more than 10 per cent of all that
21 is produced be exported.

22 4. An insurance fund be provided in
23 escrow to protect against business loss should a spill
24 occur.

25 5. A clean-up corporation be established,

1
2 funded by the oil companies, not unlike Clean Gulf As-
3 sociates in the Louisiana Gulf.

4 6. The federal government give 10 per
5 cent of the lease price to the state government, and 5
6 per cent to the municipality that parallels the lease-
7 holds to defray the socio-economic impact that is likely
8 to follow.

9 7. The oil companies pay to the municip-
10 alities 2 per cent per annum of the rig cost for the
11 initial lease period to again defray socio-economic
12 impact of municipality or county parallel to the drill-
13 ing area.

14 8. The federal government earmark 10
15 per cent of the lease price to the research and develop-
16 ment of a non-depletable form of energy supply. (E.G.
17 solar or nuclear energy.)

18 The above suggestions are not meant to be
19 punitive but, rather, protective.

20 In summary, I believe that the economic
21 benefits coupled with the national benefits outweigh
22 the possibility of an oil spill. I further believe that
23 technological advances and other safeguards can greatly
24 reduce the possibility of an oil spill. I further be-
25 lieve that a curtailment of energy use would be economically

1 harmful. I feel that this country has economically pro-
2 gressed based on its national unity. Let that progress-
3 ion not be thwarted by parochialism and emotional fears.
4

5 There are a couple of things I would like
6 to add. I guess as the Mayor of a resort, it would be
7 very, very easy when first talked about to take a nega-
8 tive position. I think most of the constituencies in
9 resorts would find that a very defensible position.

10 I felt, rather, that the elected officials
11 throughout this country are not expected to act on an
12 emotional basis. They are expected to try to inform
13 themselves and, in fact, present their findings and their
14 analysis of their findings to their constituency, be
15 it federal representative, state or municipal repre-
16 sentative.

17 I have traveled to Louisiana. Independ-
18 ently, I have met with several people in Louisiana. I
19 saw the Clean Gulf Associates operations there. I
20 spoke to Dr. St. Amant, who is the Assistant Director
21 of the Louisiana Wildlife and Game Commission and has
22 been so and occupied that position for 25 years, and
23 satisfied myself that, in fact, the oil spills that they
24 have had there, there has been no detrimental, lasting
25 effect on the wildlife and/or the shellfish or fisheries

1
2 industry.

3 I have read several articles, most no-
4 tably, I guess, the article by Dr. Dale Strumm relative
5 to the Santa Barbara oil spill, and that article is en-
6 titled, "Santa Barbara Lives", and I was amazed at the
7 discrepancy that existed between the estimates of the
8 oil that was actually spilled.

9 If my memory serves me correctly, those
10 estimates ranged from 18,500 barrels spilled to 70,000
11 barrels spilled.

12 I think many of us and many of the emo-
13 tional actions that people had to offshore oil are un-
14 founded. I think, in fact, that the news media has
15 distorted much and those that would choose to have facts
16 distorted and create images that are untrue have done
17 so.

18 I feel that dependence on imported oil
19 is something we can ill afford. I think the current
20 unemployment that exists in the country and the un-
21 employment in the State of New Jersey, which approaches
22 14 per cent, that there is no way in the world that you
23 can possibly attack that unemployment unless industry
24 is concerned and is enticed to come into our state.

25 I feel very strongly that what we are

1
2 looking at now is a short-term problem with long-term
3 ramifications. That's why one of my suggestions in-
4 dicates that a sum of money should be put aside for de-
5 finitive research on an energy supply that's non-de-
6 pletable.

7 In that regard, I think long range, we
8 won't have this problem to deal with.

9 I feel very, very strongly that the facts
10 have not been brought out to the general public insofar
11 as the probability of an oil spill. I think it's dis-
12 torted. I think technological advances that I am aware
13 of, flow-out preventors, etc., have worked. I think
14 that the advances that have been made from 25 years ago
15 render the probability of an oil spill less great now
16 than then.

17 I think that when we talk in terms of
18 oil spills, I think we are talking in terms of Santa
19 Barbara and the Gulf of Mexico in which the oil rigs
20 are intimately closer to land than is envisioned in
21 the Baltimore Canyon Trough.

22 I think that the mere fact that 2 per
23 cent, if my figures are correct, in 1971 of the oil spilled
24 in the world's water came from offshore oil rigs and
25 tankers and barges and commercial and pleasure craft.

1
2 contribute much, much more than that.

3 I think that the probability of hazard
4 is lesser. I think it needs to be said in terms that
5 the general public can understand. I think they are
6 qualified to measure the possible economic pluses
7 against the probability of an oil spill. I think that
8 that probability should not be overstated but should
9 be stated in realistic terms.

10 I thank you for this opportunity to say
11 my piece and I would hope that any questions you might
12 have, you would please address them to me now. (APPLAUSE)

13 JUDGE MOORE: Thank you, Mayor. I guess
14 we have no questions. Mr. John Crandall. Mr. Swan.
15 I understand you have been granted extended time, Mr.
16 Swan. Is that correct?

17 MR. WILLIAM D. SWAN, JR.: I don't intend
18 to take any.

19 JUDGE MOORE: All right, fine.

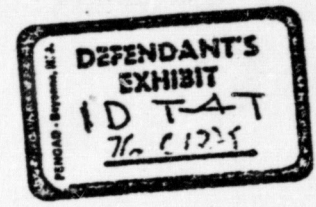
20 MR. SWAN: My name is William D. Swan, Jr.
21 and I am the Executive Director of the Association for
22 a Better New York. I represent a group of New York City
23 businessmen which was formed approximately five years
24 ago to work for a healthy economic climate which would
25 keep and attract businesses in New York City.

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GLOUCESTER COUNTY DEVELOPMENT COUNCIL, INC.



STATEMENT OF THE
GLOUCESTER COUNTY DEVELOPMENT COUNCIL, INC.

BEFORE THE
UNITED STATES DEPARTMENT OF INTERIOR

at its Public Hearing on the Proposed
Oil and Gas Lease Sale for the Mid-
Atlantic Region.

Sheraton Deauville Hotel, Atlantic City,
New Jersey, Thursday, January 29, 1976.

My name is John Crandall. I am the Executive Director of the Gloucester County Development Council, Inc., with offices in the Herbert Building, Blackwood Road, Sewell, New Jersey.

The Gloucester County Development Council, Inc. is a non-profit, public benefit corporation endorsed by the Gloucester County Board of Chosen Freeholders and supported financially by both public and private sectors. The membership includes participating individuals, major commercial and industrial interests, and citizen groups as well as governmental units. The broad based support received by the Council assures a representative examination of all issues that may have an impact on the economic and environmental health of Gloucester County and the region.

It is not Council policy to urge precipitate action on critical issues, nor to assume a fixed position without examining all factors bearing on both the socio-economic and environmental systems. The Council recognizes that Gloucester County is an integral part of a tri-state region, whose quality of life needs to be preserved and where possible improved.

There can be no question that the preservation and enhancement of our environment should be a high priority responsibility shared at all levels of government. It is equally true that the preservation and enhancement of a healthy business climate must be a high priority responsibility shared at all levels of government. The obligation of government to encourage economic

opportunities, leading to increased capacity to provide productive jobs, services, and rateables, is self-evident. This can be achieved without the debasement of the eco-system.

If the State of New Jersey is to halt the decay of its urban centers, bolster the educational system, provide adequate transportation complexes, and in general provide the rising quality of life the residents expect, an accomodation with the economic facts of life must be made. But not necessarily at a ruinous cost to the eco-system. There is no need to debase the environment. Environmental legislation and agencies compel land use control at every level of government - from the Federal to Borough - effective monitoring potentially destructive ecological activities. We need now to apply the same diligence in preserving and expanding the economic quality of life.

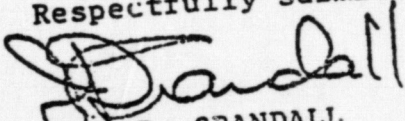
The economic base of New Jersey is energy oriented both in terms of consumption and production. Energy starved industry cannot consider an expansion of production capacity with its attendant increase in job opportunities and rateables. Indeed the concern is whether or not such industries will even remain in the State. New Jersey's eroding economic base cannot be a viable force if denied equal opportunity to share the market place with out of competitors. In brief, the State must soon strike a posture of positive action toward business and industry.

Oil and gas are the prime constituents of New Jersey's industry and a leading production cost. It seems obvious that until such time as alternative sources of energy can be developed, the production of offshore fossil fuels must be encouraged.

The basic attitude of the Gloucester County Development Council is that the proposed oil and gas leasing on the Outer Continental Shelf should be implemented as rapidly as possible, with all due consideration of environmental safeguards.

In brief, the Gloucester County Development Council, Inc. urges the expedition of the proposed leasing program for oil and gas on the Outer Continental Shelf.

Respectfully submitted,


JOHN D. CRANDALL
Executive Director



NEW YORK
Outer Continental Shelf
Office

FOR RELEASE: Immediately

CONTACT: Barbara Karlen
 264-2960

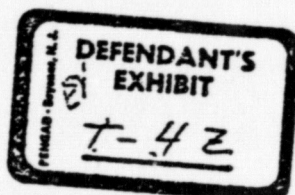
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BUREAU OF LAND MANAGEMENT

News Release

UNITED STATES DEPARTMENT OF THE INTERIOR

August 25, 1976



**INTERIOR ACCEPTS TOTAL BIDS OF \$1.13 BILLION FOR
 FIRST OCS LEASE SALE ON ATLANTIC FRONTIER**

The Interior Department announced today that it has accepted high bonus bids totaling \$1,127,936,425.32 for offshore drilling rights on 93 tracts of sub-merged lands off the coasts of New Jersey and Delaware in the Baltimore Canyon trough. These tracts consist of 214,272 hectares (529,466 acres).

The tracts were among the 154 offered in the sale of oil and gas leases (OCS Sale #40) held in New York City on August 17, 1976. The 154 tracts offered comprised 354,816 hectares (876,750 acres).

At the lease sale there were 410 bids on 101 tracts for a total amount of money exposed of \$3,513,411,801.66, a figure more than double that received in the previous OCS frontier sales in Southern California and the Gulf of Alaska. The sum of the high bids at the sale was \$1,135,802,178.92.

Interior rejected high bids received on 8 tracts covering 18,432 hectares (45,545 acres) for insufficiency of bid. The rejected bids totaled \$7,865,753.60.

The tracts rejected were:

#45	Exxon	\$1,508,000.00
#90	General Crude Oil, Texas	
	Eastern Transmission	475,545.60
#92	Murphy Oil, Ocean Production	759,000.00
#95	Houston Oil & Minerals Corp.	350,208.00
#101	Freeport Minerals, Transco	
	Exploration	441,000.00
#122	Exxon	208,000.00
#129	Exxon	3,912,000.00
#137	Exxon	212,000.00
	TOTAL	\$7,865,753.60

2722

-2-

The highest bid accepted for a single tract was \$107,788,600.00 for Tract #29, one of the high-royalty tracts, offered by a combine of Mobil Oil, Amerada Hess, Anadarko Production, Sun Oil (Delaware), and Pan Canadian Petroleum. The per hectare value of this bid is \$46,783.25 or \$18,932.92 per acre.

All 15 of the high-royalty tracts received bids and 13 were accepted. A statistical summary of all the bids on all the tracts will be available from the New York OCS Office for \$1.00 in about two weeks.

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Form 1000-1
(May 1970)

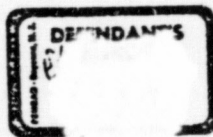
UNITED STATES
DEPARTMENT OF THE INTERIOR
BUREAU OF LAND MANAGEMENT

OIL AND GAS LEASE OF SUBMERGED LANDS
UNDER THE OUTER CONTINENTAL SHELF LANDS ACT

Office New York, New York	
Serial Number OCS-A 0101	
Cash Bonus \$467,712.00	
Rental Rate \$8.00 per hectare	
Minimum Royalty Rate \$8.00 per hectare	Royalty Rate 1/6

This lease is made and effective as of **SEP 1 1976** (hereinafter called the "Effective Date")
by and between the United States of America (hereinafter called the "Lessor"), by the Manager,
New York Outer Continental Shelf Office, Bureau of Land Management, its authorized officer, and

Houston Oil & Minerals Corporation 1002



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SEP 1 10 05 AM '76
BUREAU OF LAND
MANAGEMENT
NEW YORK OUTER CON-
TINENTAL SHELF OFFICE

(hereinafter called the "Lessee"). In consideration of the cash payment heretofore made by the Lessee to the Lessor and in consideration of the promises, terms, conditions, and covenants contained herein, the parties hereto agree as follows:
Sec. 1. Statutes and Regulations. This lease is made pursuant to the Outer Continental Shelf Lands Act of August 7, 1953 (67 Stat. 462; 43 U.S.C. Secs. 1331-1343) (hereinafter called the "Act"). This lease is subject to all the provisions of the Act and to all the terms, conditions, and requirements of the valid regulations promulgated by the Secretary of the Interior (hereinafter called the "Secretary") thereunder in existence upon the effective date of this lease, all of which are incorporated herein and, by reference, made a part hereof. This lease shall also be subject to regulations hereafter issued by the Secretary pursuant to his authority under section 5(a)(1) of the Act to prescribe and amend any time such rules and regulations as he may determine to be necessary and proper in order to provide for the prevention of waste and for the conservation of the natural resources of the Outer Continental Shelf, and for the protection of correlative rights therein, which regulations shall be deemed incorporated herein and, by reference, made a part hereof when promulgated.

Sec. 2. Rights of Lessee. The Lessor hereby grants and leases to the Lessee the exclusive right and privilege to drill for, mine, extract, remove, and dispose of oil and gas deposits, except helium gas, in or under the following-described area of the Outer Continental Shelf of the United States:

All of Block 277, as shown on OCS Official Protraction Diagram No. NJ 18-6

containing approximately 2304 hectares (hereinafter referred to as the "leased area"), together with:

(a) the non-exclusive right to conduct within the leased area geological and geophysical explorations in accordance with applicable regulations;
(b) the non-exclusive right to drill water wells within the leased area and to use water produced therefrom for operations pursuant to the Act free of cost, provided that such drilling is conducted in accordance with procedures approved by the Regional Oil and Gas Supervisor of the Geological Survey (hereinafter called the "Supervisor"); and
(c) the right to construct or erect and to maintain within the leased area all artificial islands, platforms, fixed or floating structures, sea walls, docks, dredged channels and spurs, buildings, plants, telegraph or telephone lines and cables, pipelines, towers, tanks, pumping stations, and other works and structures necessary to the full enjoyment of the rights granted by this lease, subject to compliance with applicable laws and regulations.

Sec. 3. Obligations of Lessee. The Lessee agrees:
(a) to comply with applicable laws and regulations;
(b) to comply with applicable laws and regulations;
(c) to comply with applicable laws and regulations;
(d) to comply with applicable laws and regulations;
(e) to comply with applicable laws and regulations;
(f) to comply with applicable laws and regulations;
(g) to comply with applicable laws and regulations;
(h) to comply with applicable laws and regulations;
(i) to comply with applicable laws and regulations;
(j) to comply with applicable laws and regulations;
(k) to comply with applicable laws and regulations;
(l) to comply with applicable laws and regulations;
(m) to comply with applicable laws and regulations;
(n) to comply with applicable laws and regulations;
(o) to comply with applicable laws and regulations;
(p) to comply with applicable laws and regulations;
(q) to comply with applicable laws and regulations;
(r) to comply with applicable laws and regulations;
(s) to comply with applicable laws and regulations;
(t) to comply with applicable laws and regulations;
(u) to comply with applicable laws and regulations;
(v) to comply with applicable laws and regulations;
(w) to comply with applicable laws and regulations;
(x) to comply with applicable laws and regulations;
(y) to comply with applicable laws and regulations;
(z) to comply with applicable laws and regulations;

(b) *Rentals and royalties.* (1) To pay rentals and royalties as follows:

Rentals. With respect to each lease year commencing prior to a discovery of oil or gas on the leased area, to pay the Lessor on or before the first day of each such year, a rental of \$8.00 per hectare or fraction thereof.

Minimum royalty. To pay the Lessor at the expiration of each lease year commencing after discovery, a minimum royalty of \$8.00 per hectare or fraction thereof or, if there is production, the difference between the actual royalty required to be paid with respect to such lease year and the prescribed minimum royalty, if the actual royalty paid is less than the minimum royalty.

Royalty on production. To pay the Lessor a royalty of 16 2/3 percent in amount or value of production saved, produced, or sold from the leased area, less of 11 percent.

that the Lessee may not be required to maintain the leased area in a condition better than that in which it was received from the Lessor. The Lessee shall not be required to maintain the leased area in a condition better than that in which it was received from the Lessor.

(3) When paid in value, royalties on production shall be due and payable monthly on the last day of the month next following the month in which the production is obtained. When paid in production, such royalties shall be delivered at pipeline connections or in tanks provided by the Lessee. Such deliveries shall be made at reasonable times and intervals and, at the Lessor's option, shall be effected either (i) on or immediately adjacent to the leased area, without cost to the Lessee, or (ii) at a more convenient point closer to shore or on shore, in which event the Lessee shall be entitled to reimbursement for the reasonable cost of transporting the royalty substance to such delivery point. The Lessee shall not be required to provide storage for royalty taken in kind in excess of tankage required when royalty is paid in value. When payments are made in production the Lessee shall not be held liable for the loss or destruction of royalty oil or other liquid products in storage from causes over which the Lessee has no control.

(c) *Insurance.* To maintain at all times the bond required prior to the issuance of this lease and to furnish such additional security as may be required by the Lessor if, after operations or production have begun, the Lessor deems such additional security to be necessary.

(d) *Drilling.* (1) To diligently drill and produce such wells as are necessary to protect the Lessor from loss by reason of production on other properties or, in lieu thereof, with the consent of the Supervisor, to pay a sum determined by the Supervisor as adequate to compensate the Lessor for failure to drill and produce any such well. In the event that this lease is not being maintained in force by other production of oil or gas in paying quantities or by other approved drilling or reworking operations, such payments shall be considered as the equivalent of production in paying quantities for all purposes of this lease.

(2) After due notice in writing, to diligently drill and produce such other wells as the Secretary may reasonably require in order that the leased area or any part thereof may be properly and timely developed and produced in accordance with good operating practice.

(3) At the election of the Lessee, to drill and produce other wells in conformity with any system of well spacing or production allotments affecting the area, field, or pool in which the leased area or any part thereof is situated, which is authorized or sanctioned by applicable law or by the Secretary.

(e) *Payments.* To make all payments to the Lessor by check, bank draft, or money order payable as indicated herein unless otherwise provided by regulations or by direction of the Secretary. Rental, royalties, and other payments shall be made payable to the United States Geological Survey and tendered to the Supervisor, except that filing charges, bonuses, and first year's rental shall be made payable to the Bureau of Land Management and remitted to the Manager of the appropriate field office of that Bureau.

(f) *Inspection.* To keep open at all reasonable times for the inspection of any duly authorized representative of the Lessor, the leased area and all wells, improvements, machinery, and fixtures thereon, and all books, accounts, and records relative to operation and surveys or investigations on or with regard to the leased area or under the lease.

(g) *Conduct of operations.* To conduct all operations under this lease in accordance with applicable law and regulations.

(h) *Indemnification.* To indemnify and save the Lessor harmless against and from any and all claims of any nature whatsoever, including without limitation claims for loss or damage to property or injury to persons, caused by, or resulting from, any operation on the leased area conducted by or on behalf of the Lessee; provided that the Lessee shall not be held responsible to the Lessor under this subsection for any loss, damage, or injury caused by, or resulting from: (1) any negligent action of the Lessor other than the exercise or performance of (or the failure to exercise or perform) a discretionary function or duty on the part of a Federal agency whether or not the discretion involved is abused; or (2) the Lessor's compliance with an order or directive of the Lessor against which an appeal by the Lessee under 30 CFR 250.81 is filed before the cause of action for such a claim arises and is pursued diligently thereafter.

(i) *Equal Opportunity Clause.* The Lessee agrees that, during the performance of this lease:

(1) The Lessee will not discriminate against any employee or applicant for employment because of race, color, religion, sex, or national origin. The Lessee will take affirmative action to ensure that applicants are employed, and that employees are treated during employment, without regard to their race, color, religion, sex, or national origin. Such action shall include, but not be limited to, the following: employment, upgrading, demotion, or transfer; recruitment or recruitment advertising; layoff or termination; rates of pay or other forms of compensation; and selection for training, including apprenticeship. The Lessee agrees to post in conspicuous places, available to employees and applicants for employment, notices to be provided by the Secretary setting forth the provisions of this Equal Opportunity clause.

(2) The Lessee will, in all solicitations or advertisements for employment placed by or on behalf of the Lessee, state that all qualified applicants will receive consideration for employment without regard to race, color, religion, sex, or national origin.

(3) The Lessee will send to each labor union or representative of workers with which the Lessee has a collective bargaining agreement or other contract or understanding, a copy of this lease, and will provide by the Lessee, after the time the Lessee has been notified of the Lessee's commitment to

under this Equal Opportunity clause, and will post copies of the notice in conspicuous places available to employees and applicants for employment.

(4) The Lessee will comply with all provisions of Executive Order No. 11246 of September 24, 1965, as amended, and the rules, regulations, and relevant orders of the Secretary of Labor.

(5) The Lessee will furnish all information and reports required by Executive Order No. 11246 of September 24, 1965, as amended, and by the rules, regulations, and orders of the Secretary of Labor, or pursuant thereto, and will permit access to his books, records, and accounts by the Secretary of the Interior and the Secretary of Labor for purposes of investigation to ascertain compliance with such rules, regulations, and orders.

(6) In the event of the Lessee's noncompliance with the Equal Opportunity clause of this contract or with any of the said rules, regulations, or orders, this lease may be cancelled, terminated or suspended in whole or in part and the Lessee may be declared ineligible for further Government contracts or leases in accordance with procedures authorized in Executive Order No. 11246 of September 24, 1965, as amended, and such other sanctions may be imposed and remedies invoked as provided in Executive Order No. 11246 of September 24, 1965, as amended, or by rule, regulation, or order of the Secretary of Labor, or as otherwise provided by law.

(7) The Lessee will include the provisions of paragraphs (1) through (7) of this subsection 3(i) in every contract, subcontract, or purchase order unless exempted by rules, regulations, or orders of the Secretary of Labor issued pursuant to Section 204 of Executive Order No. 11246 of September 24, 1965, as amended, so that such provisions will be binding upon each contractor, subcontractor, or vendor. The Lessee will take such action with respect to any contract, subcontract, or purchase order as the Secretary of the Interior may direct as a means of enforcing such provisions including sanctions for noncompliance. Provided, however, that in the event the Lessee becomes involved in, or is threatened with, litigation with a contractor, subcontractor, or vendor as a result of such direction by the Secretary of the Interior, the Lessee may request the United States to enter into such litigation to protect the interests of the United States.

(j) *Certification of nonsegregated facilities.* By entering into this lease, the Lessee certifies that Lessee does not and will not maintain or provide for Lessee's employees any segregated facilities at any of Lessee's establishments, and that Lessee does not and will not permit Lessee's employees to perform their services at any location, under Lessee's control, where segregated facilities are maintained. The Lessee agrees that a breach of this certification is a violation of the Equal Opportunity clause in this lease. As used in this certification, the term "segregated facilities" means, but is not limited to, any waiting rooms, work areas, rest rooms and wash rooms, restaurants and other eating areas, time clocks, locker rooms and other storage or dressing areas, parking lots, drinking fountains, recreation or entertainment areas, transportation, and housing facilities provided for employees which are segregated by explicit directive or are in fact segregated on the basis of race, color, religion, or national origin, because of habit, local custom, or otherwise. The Lessee further agrees that (except where Lessee has obtained identical certifications from proposed contractors and subcontractors for specific time periods) Lessee will obtain identical certifications from proposed contractors and subcontractors prior to award of contracts or subcontracts exceeding \$10,000 which are not exempt from the provisions of the Equal Opportunity clause; that Lessee will retain such certifications in Lessee's files; and that Lessee will forward the following notice to such proposed contractors and subcontractors (except where proposed contractor or subcontractor has submitted identical certifications for specific time periods). Notice to prospective contractors and subcontractors of requirement for certification of nonsegregated facilities. A Certification of Nonsegregated Facilities, as required by the May 9, 1967 order (32 F.R. 7439, May 19, 1967) on Elimination of Segregated Facilities, by the Secretary of Labor, must be submitted prior to the award of a contract or subcontract exceeding \$10,000, which is not exempt from the provisions of the Equal Opportunity clause. Certification may be submitted either for each contract and subcontract or for all contracts and subcontracts during a period (i.e., quarterly, semiannually, or annually).

(k) *Assignment of lease.* To file for approval with the appropriate office of the Bureau of Land Management any instrument of transfer of this lease, or any interest therein, required to be filed under applicable regulations, within the time and in the manner prescribed by the applicable regulations.

Sec. 4. *Term.* This lease shall continue for a period of 5 years from the effective date of this lease and so long thereafter as oil or gas may be produced from the leased area in paying quantities, or drilling or well reworking operations, as approved by the Secretary, are conducted thereon.

Sec. 5. *Cooperative or Unit Plan.* Lessee agrees that, within 30 days after demand by Lessor, Lessee will subscribe to and operate under such cooperative or unit plan for the development and operation of the area, field, or pool, or part thereof, embracing lands subject to this lease as the Secretary may determine to be practicable and necessary or advisable in the interest of conservation. Where any provision of a cooperative or unit plan of development which has been approved by the Secretary, and which by its terms affects the leased area or any part thereof, is inconsistent with a provision of this lease, the provision of such cooperative or unit plan shall govern.

Sec. 6. *Reservations to Lessor.* All rights in the leased area not expressly granted to the Lessee by the Act, the regulations, or this lease are hereby reserved to the Lessor. Without limiting the generality of the foregoing, such reserved rights include:

Stipulation No. 1

If the Supervisor, having reason to believe that a site, structure, or object of historical or archeological significance, hereinafter referred to as "cultural resource," may exist in the lease area, gives the lessee written notice that the lessor is invoking the provisions of this stipulation, the lessee shall upon receipt of such notice comply with the following requirements:

Prior to any drilling activity or the construction or placement of any structure for exploration or development on the lease, including but not limited to, well drilling and pipeline and platform placement, hereinafter in this stipulation referred to as "operation," the lessee shall conduct geophysical surveys to determine the potential existence of any cultural resource that may be affected by such operations. All data produced by such geophysical surveys shall be examined by the Supervisor to determine if anomalies are present which suggest the existence of a cultural resource that may be adversely affected by any lease operation.

If such anomalies exist the lessee shall: 1) locate the site of such operation so as not to adversely affect the anomaly identified; or 2) establish, to the satisfaction of the Supervisor, on the basis of further archeological investigation conducted by a qualified marine archeological surveyor using such survey equipment and techniques as deemed necessary by the Supervisor, either that such operation will not adversely affect the anomaly identified or that the potential cultural resource suggested by the occurrence of the anomaly does not exist. A report of this investigation prepared by the marine archeological surveyor shall be submitted to the Supervisor for review. Should the supervisor determine that the existence of a cultural resource which may be adversely affected by such operation is sufficiently established to warrant protection, the lessee shall take no action that may result in an adverse effect on such cultural resource until the Supervisor has given directions as to its disposition.

The lessee agrees that if any site, structure, or object of historical or archeological significance should be discovered during the conduct of any operations on the leased area, he shall report immediately such findings to the Supervisor, and make every reasonable effort to preserve and protect the cultural resource from damage until the Supervisor has given directions as to its disposition.

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Stipulation No. 2

If the Supervisor having reason to believe that an area of special biological significance may exist in the lease area, gives the lessee written notice that the lessee is invoking the provisions of this stipulation, the lessee shall upon receipt of such notice comply with the following requirements:

Prior to any drilling activity or the construction or placement of any structure for exploration or development of lease areas including, but not limited to, well drilling and pipeline and platform placement, hereinafter in this stipulation referred to as "operation", the lessee shall conduct site specific surveys, as approved by the Supervisor, to determine the actual existence of an area of special biological significance that may be adversely affected by any lease operation. If such surveys indicate the existence of such an area, the lessee shall: 1) relocate the site of such operation so as not to adversely affect the area identified; or 2) establish, to the satisfaction of the Supervisor, on the basis of the site specific survey, either that such operation will not adversely affect the area identified or that the potential biological resource suggested by the occurrence of the anomaly does not exist.

All data obtained in the course of any biological surveys conducted pursuant to the provisions hereof shall be submitted to the Supervisor with any application by the lessee for drilling or other activity with a copy to the Manager, New York OCS Office. Should the Supervisor determine, contrary to the contentions of the lessee, that the existence of a biological resource which may be adversely affected by such operation is sufficiently established to warrant protection, the lessee shall take no action that may result in any adverse effect on such resource until the Supervisor has given the lessee directions with respect to the resource.

The lessee agrees that, if any site, structure, or object of biological significance should be discovered during the conduct of any operations on the leased area, he shall report such findings to the Supervisor, and make every reasonable effort to preserve and protect the resource from damage until the Supervisor has given the lessee directions with respect to the resource.

Stipulation No. 3

Structures for drilling or production, including pipelines and subsea systems, shall be kept to the minimum necessary for proper exploration, development, and production and, to the greatest extent consistent therewith, shall be placed so as not to interfere unnecessarily with other significant uses of the Outer Continental Shelf, including commercial fishing.

To this end, no structure for drilling or production, including pipelines and subsea systems, may be placed on the Outer Continental Shelf until the Supervisor has determined that the structure is necessary for the proper exploration, development, or production of the lease area and that no reasonable alternative placement would cause less interference with other significant uses of the Outer Continental Shelf, including commercial fishing. The lessee's exploratory and development plans, filed under 30 CFR 250.34, shall identify the anticipated placement and grouping of necessary structures including pipelines and subsea production systems, showing how such placement and grouping will have the minimum practicable effect on other significant uses of the Outer Continental Shelf, including commercial fishing.

Stipulation No. 4

If feasible pipeline rights-of-way can be determined and obtained and, if laying such pipelines is technically and economically feasible, no crude oil production will be transported by surface vessel from offshore production sites to adjacent onshore facilities except in case of emergency. Determinations as to emergency conditions and the technical and economic feasibility of pipeline laying will be made by the Supervisor. Barges will not be used for surface transportation except in emergency situations where the Supervisor determines that the use of no other vessels is feasible.

The lessor specifically reserves the right to require that any pipeline to be used for transporting production from this lease to shore be placed in certain designated areas or corridors.

Wherever technically and economically feasible, all pipelines, including both flow lines and gathering lines for oil and gas, shall be buried to a depth suitable for adequate protection from water currents, storm scouring, fisheries trawling gear, and other uses as determined by the Department of the Interior permitting agency on a case-by-case basis.

Surveillance of all buried pipelines shall be conducted by the lessor at regular intervals to ensure that they remain buried. Surveillance methods utilized shall be those specified in present and future OCS Orders and regulations or as approved by the Department of the Interior permitting agency.

Stipulation No. 6

(a) Whether or not compensation for such damage or injury might be due under a theory of strict or absolute liability or otherwise, the lessee assumes all risks of damage or injury to persons or property, which occurs in, on, or above the Outer Continental Shelf, to any person or persons who are agents, employees or invitees of the lessee, its agents, independent contractors or subcontractors doing business with the lessee in connection with any activities being performed by the lessee in, on, or above the Outer Continental Shelf, if such injury or damage to such person or property occurs by reason of the activities of any agency of the U.S. Government, its contractors or subcontractors, or any of their officers, agents, or employees, being conducted as a part of, or in connection with, the programs and activities of the Commanding Officer, Naval Air Station, Lakehurst, New Jersey. The lessee assumes this risk whether such injury or damage is caused in whole or in part by any act or omission, regardless of negligence or fault, of the United States, its contractors or subcontractors, or any of their officers, agents, or employees.

The lessee further agrees to indemnify and save harmless the United States against all claims for loss, damage, or injury sustained by the lessee and to defend at its own expense the United States against all claims for loss, damage, or injury sustained by the agents, employees, or invitees of the lessee, its agents, or any independent contractors or subcontractors doing business with the lessee in connection with the programs and activities of the aforementioned military installation, whether the same be caused in whole or in part by the negligence or fault of the United States, its contractors or subcontractors, or any of their officers, agents or employees and whether such claims might be sustained under theories of strict or absolute liability or otherwise.

(b) The lessee agrees to control his own electromagnetic emissions and those of his agents, employees, invitees, independent contractors or subcontractors emanating from individual designated defense warning areas in accordance with requirements specified by the commander of the appropriate onshore military installation, i.e., Commanding Officer, Naval Air Station, Lakehurst, New Jersey, to the degree necessary to prevent damage to, or unacceptable interference with Department of Defense flight, testing or operational activities, conducted within individual designated warning areas.

Necessary monitoring, control, and coordination with the lessee, his agents, employees, invitees, independent contractors or subcontractors, will be effected by the commander of the appropriate onshore military installation conducting operations in the particular warning area; Provided, however, that control of such electromagnetic communication shall in no instance prohibit all manner of electromagnetic communication during any period of time between a lessee, its agents, employees, invitees, independent contractors or subcontractors and onshore facilities.

(c) The lessee, when operating or causing to be operated on its behalf boat or aircraft traffic into the individual designated warning areas shall enter into an agreement with the commander of the appropriate onshore military installation, i.e., Commanding Officer, Naval Air Station, Lakehurst, New Jersey, utilizing an individual designated warning area prior to commencing such traffic. Such agreement will provide for positive control of boats and aircraft operating into the warning areas at all times.

Stipulation No. 7

To provide information to coastal states and thus to assist them in planning for the impact of activities during exploration under this lease, the lessee shall submit, for review and comment, to the Governor of each Mid-Atlantic state a "Notice of Support Activity for the Exploration Program" (herein called "Notice").

For the purpose of this stipulation Mid-Atlantic states include New York, New Jersey, Pennsylvania, Delaware, Maryland, and Virginia. The lessee shall not be required to include privileged information in this Notice. At his discretion, the lessee may submit either a separate Notice for each Exploration Plan submitted on a lease under 30 CFR 250.34, or a Notice for two or more plans on one or more leases. The Notice shall not be subject to approval or disapproval by the Supervisor.

A copy of the Notice shall be submitted to the Supervisor no later than the date of submission of the Exploration Plan, with a certification that the Notice has already been submitted to the Governor of each Mid-Atlantic state. A lessee who submits a Notice for two or more Exploration Plans shall not be required to supply additional copies of the notice, but may instead refer to that prior submission. Before the Supervisor approves or disapproves the Exploration Plan, he shall allow at least 30 days from the date of receipt of the certification for the Governors to submit comments on the Notice to the lessee. Subsequent to submission of the certification, significant changes in estimated support activities will be forwarded by the lessee, as an amendment to the Notice, to the Governors of the Mid-Atlantic states and the Supervisor.

The Notice shall include with respect to the lessee and his contractors:

- (1) A description of the onshore and nearshore support facilities, including site and size, expected to be constructed, leased, rented, or otherwise procured in affected areas;
- (2) Amount and location of acreage expected to be required within the state for facilities, including the need for storage space for supplies;
- (3) An estimate of the frequency of boat and aircraft departures and arrivals, on a monthly basis, and the possible onshore location of terminals;
- (4) The approximate number of persons who are expected to be engaged in onshore support activities and transportation, the approximate number of local personnel who are expected to be employed by or in support of the exploration program, and the approximate total number of persons who are expected to be employed for the exploration program;
- (5) Estimates of the approximate addition to the population, on a county basis, due to the exploration program and the approximate number of persons needing housing and other facilities;
- (6) An estimate of any significant quantity of major supplies and equipment to be procured within the state; and
- (7) The onshore address of the lessee's operation officers and of the contractors' offices involved in the exploratory operation.

2730

Stipulation No. 10

All reservoirs underlying this lease which extend into a lease covering the higher royalty tracts as indicated by drilling and other information, shall be operated and produced only under a unit agreement covering the lease for the higher royalty tracts and approved by the Supervisor. Such a unit agreement shall provide for a fair and equitable allocation of production and costs. The Supervisor shall prescribe the method of allocating production and costs in the event operators are unable to agree on such a method.

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(a) *Geological and geophysical exploration; right-of-way.* The right to authorize the conduct of geological and geophysical exploration in the leased area which does not interfere with or endanger actual operations under this lease, and the right to grant such easements or right-of-way upon, through, or in the leased area as may be necessary or appropriate in the working of other lands or to the treatment and shipment of product therefrom by or under authority of the United States, its Lessee or Permittees.

(b) *Leases of sulfur and other minerals.* The right to grant leases of any mineral other than oil and gas within the leased area or any part thereof. No lease of other mineral shall authorize or permit the Lessee thereunder unreasonably to interfere with or endanger operations under this lease.

(c) *Purchase of production.* In time of war, or when the President of the United States shall so prescribe, the right of first refusal to purchase at the market price all or any portion of the oil or gas produced from the leased area, as provided in Section 12(b) of the Act.

(d) *Taking of royalties.* The right to determine whether royalty will be taken in the amount or the value of production.

(e) *Helium.* Pursuant to Section 12(f) of the Act, the ownership of and the right to extract helium from all gas produced under this lease.

(f) *Suspension of operations during war or national emergency.* Upon recommendation of the Secretary of Defense, during a state of war or national emergency declared by the Congress or President of the United States after August 7, 1953, the authority of the Secretary to suspend any or all operations under this lease, as provided in Section 12(c) of the Act; *Provided*, That just compensation shall be paid by the Lessor to the Lessee.

(g) *Restriction of exploration and operations.* The right, as provided in Section 12(d) of the Act, to restrict from exploration and operations the leased area or any part thereof which may be designated by and through the Secretary of Defense, with the approval of the President, as, or as part of, an area of the Outer Continental Shelf needed for national defense; and so long as such designation remains in effect no exploration or operations may be conducted on the surface of the leased area or the part thereof included within the designation except with the concurrence of the Secretary of Defense; and if operations or production under this lease within any such restricted area shall be suspended, any payments of rentals and royalty prescribed by this lease likewise shall be suspended during such period of suspension of operations and production, and the term of this lease shall be extended by adding thereto any such suspension period, and the Lessor shall be liable to the Lessee for such compensation as is required to be paid under the Constitution of the United States.

Sec. 7. Directional Drilling. A directional well drilled under the leased area from a surface location on nearby land not covered by this lease shall be deemed to have the same effect for all purposes of this lease as a well drilled from a surface location on the leased area. In such circumstances, drilling shall be considered to have been commenced on the leased area when drilling is commenced on the nearby land for the purpose of directionally drilling under the leased area, and production of oil or gas from the leased area through any directional well surfaced on nearby land or drilling or reworking of any such directional well shall be considered production or drilling or reworking operations (as the case may be) on the leased area for all purposes of this lease. Nothing contained in this paragraph is intended or shall be construed as granting to the Lessee any leasehold interests, licenses, easements, or other rights in or with respect to any such nearby land in addition to any such leasehold interests, licenses, easements, or other rights which the Lessee may have lawfully acquired under the Act or from the Lessor or others.

Sec. 8. Surrender of Lease. The Lessee may surrender this entire lease or any officially designated sub-interest of the leased area by filing with the appropriate office of the Bureau of Land Management a written relinquishment in triplicate, which shall be effective as of the date of filing. No surrender of this lease or of any portion of the leased area shall relieve the Lessee or his surety of the obligation to make payment of all accrued rentals and royalties or to abandon all wells on the area to be surrendered in a manner satisfactory to the Supervisor.

Sec. 9. Removal of Property on Termination of Lease. Upon the termination of this lease in whole or in part, or the surrender of the lease in whole or in part, as herein provided, the Lessee shall within a period of 1 year thereafter remove from the premises no longer subject to the lease all structures, machinery, equipment, tools, and materials in accordance with applicable regulations and orders of the Supervisor; *Provided, however*, That the Lessee may continue to maintain any such property on the leased area for whatever longer period it may be needed, as determined by the Supervisor, for producing wells or for drilling or producing on other leases.

Sec. 10. Remedies in Case of Default. (a) Whenever the Lessee fails to comply with any of the provisions of the Act, or of this lease, or of the regulations issued under the Act and in force and effect on the effective date of this lease, the lease shall be subject to cancellation in accordance with the provisions of Section 5(b) of the Act; *Provided, however*, That the 30-day notice provision applicable to non-producing leases under Section 5(b)(1) of the Act shall also apply as a prerequisite to the institution of any legal action by the Lessor to cancel this lease while it is in a producing status. Nothing in this subsection shall be construed to apply to, or require any notice with respect to, any legal action instituted by the Lessor other than an action to cancel the lease pursuant to Section 5(b) of the Act.

(b) Whenever the Lessee fails to comply with any of the provisions of the Act, or of this lease, or of any regulations promulgated by the Secretary under the Act, the Lessor may exercise any legal or equitable remedy or remedies which the Lessor may have, including appropriate action under the penalty provisions of Section 5(a)(2) of the Act; *however*, the remedy of cancellation of the lease may be exercised only under the provisions of Section 5(b) and Section 8(l) of the Act.

(c) A waiver of any particular violation of the provisions of the Act, or of this lease, or of any regulations promulgated by the Secretary under the Act, shall not prevent the cancellation of this lease or the exercise of any other remedy or remedies under paragraphs (a) and (b) of this section by reason of any other such violation or for the same violation occurring at any other time.

Sec. 11. Heirs and Successors in Interest. Each obligation hereunder shall extend to and be binding upon, and every benefit hereof shall inure to, the heirs, executors, administrators, successors, or assigns, of the respective parties hereto.

Sec. 12. Unlawful Interest. No member of, or Delegate to, Congress, or Resident Commissioner, after his election or appointment, or either before or after he has qualified, and during his continuance in office, and no officer, agent, or employee of the Department of the Interior, except as provided in 43 CFR 7.4(a)(1), shall be admitted to any share or part in this lease or derive any benefit that may arise therefrom; and the provisions of Section 3741 of the Revised Statutes (41 U.S.C. Sec. 22), as amended, and Sections 431, 432, and 433 of Title 18 of the United States Code, relating to contracts made or entered into, or accepted by or on behalf of the United States, form a part of this lease so far as the same may be applicable.

THE UNITED STATES OF AMERICA

HOUSTON OIL & MINERALS CORPORATION

John E. Walters
(Signature of Lessee)

Vice President

ATTEST:

Evangelina L. Williams
(Secretary)

(Signature of Lessee)

Frank Basile
(Authorized Officer)

Manager
New York Outer Continental Shelf Office
Bureau of Land Management
(Title)

SEP 1 1976

(Date)

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(Signature of Lessee)

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MANAGEMENT

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If this lease is executed by a corporation, it must bear the corporate seal.

Allied Chemical Corporation
 Union Texas Petroleum Division
 P.O. Box 2120
 Houston, Texas 77001
 Attention: Charles H. Moerbe

Amerada Hess Corporation
 P.O. Box 2040
 Tulsa, Oklahoma 74102
 Attention: John S. Miller

American Petrofina Exploration Company
 1100 First City East Building
 Houston, Texas 77002
 Attention: W.H. Rieniets

Aminoil Resources, Inc.
 P.O. Box 94193
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 Attention: Ward R. Jones

Anadarko Production Company
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 Houston, Texas 77001
 Attention: Donald L. Bridges

Diamond Shamrock Corporation
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Freeport Minerals Company
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 150 East 42nd Street
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 Attention: C.J. Caskey

Murphy Oil Corporation
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 Attention: Harry Simmons

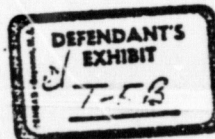
Ocean Production Company
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 Attention: Phil J. Katich

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 Attention: W. F. Bolding

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2734

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Cities Service Company
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Skelly Oil Company
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The Superior Oil Company
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Attention: R.W. Dye

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Attention: Jack Morris

Texaco Inc.
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Tulsa, Oklahoma 74102
Attention: D.T. McCreary

Pages 2736
to 2767 are
not included
in this
appendix

2763

STATEMENT BEFORE THE
CALIFORNIA ASSEMBLY SUBCOMMITTEE ON ENERGY
October 18, 1976, Los Angeles, California

Mr. Chairman and Assemblymen; I have been asked by Mr. Coulter Stewart to appear as a witness before you in these hearings on future gas supplies for the State of California.

Since most of your current supplies are being derived from Northwest and Southeast New Mexico, and from West Texas, I will confine my remarks primarily to these areas.

SAN JUAN BASIN

First, in Northwest New Mexico there is a geologic area called the San Juan Basin which includes approximately 6,000 square miles. This basin is almost entirely gas productive, from sandstone reservoirs found at depths ranging from 1,500 to 9,000 feet. All of the gas producing zones are "tight" reservoirs with reservoir characteristics that result in low production rates and limited drainage areas.

Initial discoveries in this Basin occurred in the late 1920's and development wells were continuously added through the early 1950's, resulting in approximately 8,000 gas wells which have been drilled. Many of these wells were drilled on a spacing of 160 to 320 acres. Numerous wells were twinned for completion in a different zone.

After years of production it has become evident that the current wells will not efficiently drain all of the remaining reserves on a spacing as large as 320 acres. There exists therefore, an opportunity to add recoverable reserves by infill drilling on 160 acre spacing. Additionally, reserves

and deliverability may probably be increased by new stimulation practices such as massive hydraulic fracturing. This has the effect of enlarging or inducing fractures in the reservoir, widening the flow channels to the well bore, and laterally increasing the drainage area of each well completed within MHF practices.

We estimate that an additional 6,000 wells could be drilled as infill development wells which would provide another billion cubic feet of gas for the Southern California market. *per day*

A project of this nature would cost the operators in these fields something on the order of 3 billion dollars. Unfortunately, preliminary economics using the new FPC interstate price rate of \$1.42/MCF escalating 4¢ per year, does not yield a sufficient return for that magnitude of investment, particularly since it would not be risk free.

On the other hand, if deregulation can be accomplished, prices will be allowed to escalate in a free market to a range that would be equivalent in BTU value to the price of uncontrolled domestic oil, somewhere near the \$2.00 per MCF level.

Under the \$1.42 pricing, some infill drilling will be done in the San Juan gas fields. Under deregulation prices you can expect a more intensive drilling effort which could achieve the additional 1 BCF per day that I believe may be available to you.

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WEST TEXAS

In the various geologic basins of West Texas and S. E. New Mexico, a large portion of the old gas under interstate contracts flows west to market in Southern California. However, in West Texas, unlike the San Juan Basin, there are both interstate and intrastate markets available. Because this is essentially a "free market", practically all of the exploration effort for new reserves is being focused on prospects where, if successful, the gas can be sold to intrastate pipelines. This means that new gas reserves that are now being added, will certainly not be available for California consumption.

For example, a major wildcat drilling program is now in progress in the Canyon Sand trend of West Texas, brought about by increasing gas prices. This trend was known to be productive for two decades prior to the renewed drilling boom. Reservoir characteristics are almost identical to those found in the San Juan Basin, as previously described. The sands are "tight", and average wells flow at such low volumes as to be uneconomical at interstate fixed gas prices. However, as a result of a developing intrastate market, over 1,500 new wells have been drilled since 1971. This year the industry will expend 120 million dollars in drilling some 525 new wells. Previous reserve estimates for the Canyon Sands have been stated up to 5 TCF. Continued successful development could easily add another 3 TCF in the very near future.

My company, Mitchell Energy and Development Corporation, which is one of the largest independent operators, is very actively engaged in this

area. We hold over 300,000 acres in the trend. In our expanded capital budget for this year we have begun an eight well wildcat drilling program, plan three development wells, and will cause by our support, the drilling of ten additional wells by other operators.

COMPARISON

Comparing the two primary sources of your interstate supplies, (i.e. West Texas and the San Juan Basin) I can state that the geologic conditions, reservoir characteristics, drilling and completion practices, are almost identical in all respects to each other.

In West Texas we have seen the occurrence of a dramatic increase in exploration drilling and continued new gas completions, generated by adequate gas prices.

On the other hand virtually nothing has been done in the San Juan Basin to develop the additional deliverability that is known to exist.

This comparison should be taken into account when you consider your position on decontrol of natural gas. Hindsight suggests that had gas been decontrolled prior to the building of intrastate pipelines in West Texas, California would today be receiving that new gas which was discovered.

OTHER AREAS

There are other areas where California may possibly look for added gas resources, namely; from the states of Utah, Wyoming and Colorado.

The geologic basins in these states are prone to gas production. With the probability of new interstate gas being sold at \$1.42 per MCF, we anticipate an increase in drilling activity in those areas, which will inevitably result in the discovery of new reserves. Since virtually all of the pipelines serving the area are interstate carriers, a part of the new reserves to be found may flow to California.

CAPITAL REQUIREMENTS

Underlying all of my remarks today is the inescapable fact that all successful businesses operate solely on economic incentive. This is particularly true in the oil and gas industry, which inherently must accept higher risks. The capital requirements of the job ahead of us are tremendous. For example the industry, last year, drilled a record 39,000 wells in the U.S. Expenditures in this effort exceeded 8 billion dollars. In order to decrease dependency on foreign crude which now amounts to 40% of our oil demand, and reach for self-sufficiency - we must nearly double this effort, drilling 70,000 wells per year and expending 25 billion dollars per year in exploration and continue at this rate until 1990. At this time alternate sources of energy can be expected to contribute a measurable share towards our requirements.

Of vital importance for the formation of the necessary capital requirements of the future is the decontrol of natural gas prices. This single event will do more to accelerate exploration than any other economic incentive.

DEREGULATION

A word more about deregulation. We have all heard that the estimated cost of deregulation to all consumers in the first year will be an additional 3 to 3.5 billion dollars depending upon the source. However, I think the added cost is more fairly stated in terms of the individual. For example, a household consumer in New York City today pays \$2.73 per MCF of which \$1.98 is for local distribution, 42¢ is for pipeline transportation and only 33¢ is for gas at the wellhead. If gas were decontrolled he would bear an increase of 24¢ per MCF or about 9% of this total cost.

In this same example the household consumer would pay \$3.84 per MCF for imported Algerian LNG. That is \$1.11 per MCF more than decontrolled gas in fact 40% more, and those imports are subject to an immediate cut off by arbitrary political action or a middle east war.

My point here is that you must conduct careful research in comparing imported LNG costs versus decontrolled gas, and determine which will most effectively increase uninterrupted supplies. In my opinion decontrol will be far more effective on a unit cost basis and will certainly be a surer source.

Even if gas is not decontrolled its cost will increase. The reason for this is that transportation companies are allowed to "pass on" to the customer their capital recovery and operating costs. As supplies decline, pipelines begin operating under capacity which increases operating cost, which in turn is charged to the consumer.

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Statement
California Assembly Subcommittee - Energy
page five -A

Further, the manufacturing end-user will each year suffer curtailments which this winter will range from 30 to 60% depending upon the supplier. This results in reducing the labor force and increasing unemployment. In certain areas permanent unemployment has occurred when manufacturers have abandoned facilities in states where curtailments are imposed and have relocated in states where uninterrupted supplies are to be found. Decontrol would eventually result in a free market value of gas in every state and reduce the trend towards concentrating a growing economy and high employment in one area - while another area suffers from the opposite conditions.

SUMMARY

I presented to you my conclusions concerning the immediate future gas supplies for Southern California that may be expected from traditional supply areas.

I am confident that additional reserves exist in the San Juan Basin which could be made available by a systematic program of infill drilling. This supply will not be substantially increased under present economic restrictions but can be expected in the event of deregulated gas prices.

In West Texas most of the new gas being developed which would have normally found its way to California, is being captured by intrastate markets. As a result you may not anticipate significant additions from this area.

In other areas served by interstate pipelines that supply California, some level of new gas supplies will be developed by increased exploration as a result of the new \$1.42 per MCF price now allowed.

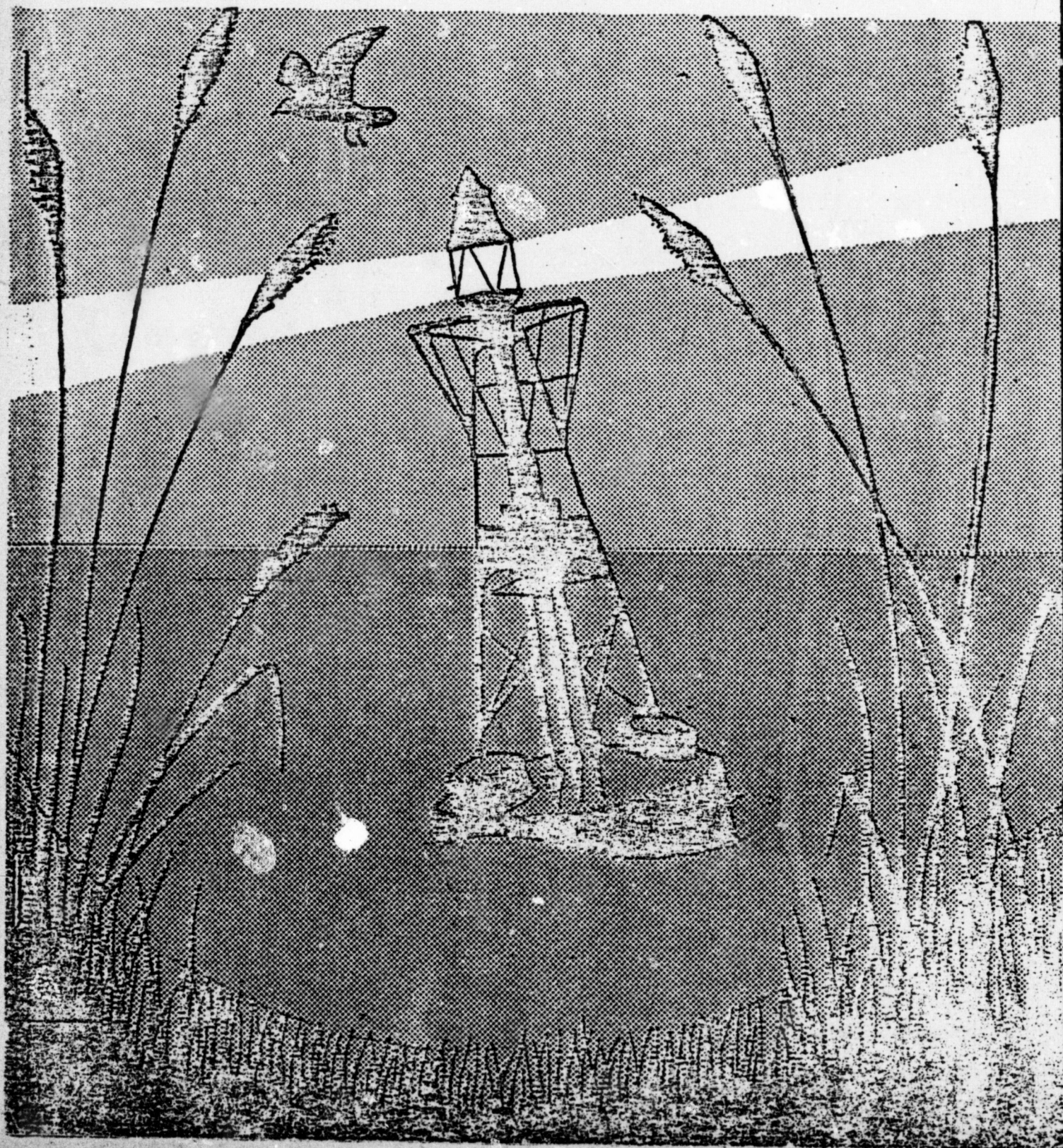
If deregulation can be accomplished in the 95th Congress you may expect an important increase in gas energy resources. Under a free market climate these new resources will be developed as rapidly as possible, but in any event peak production available to you will not occur until 3 to 5 years after decontrol, due to lead time for drilling and development.

We are already too late. Any further delay will only serve to deepen the gas supply crisis. The oil and gas exploration industry can react to close the gap, but it cannot proceed at the necessary pace without the economic incentive and the positive support of our government and each citizen that depends upon energy for his job, his transportation, and the comforts of his warm house. And that citizen described is every one of us.

THANK YOU.

NEW JERSEY DEPARTMENT OF ENVIRONMENTAL PROTECTION
BRENDAN BYRNE
2796 GOVERNOR
DAVID J. BARDIN
COMMISSIONER

ALTERNATIVES FOR THE COAST 1976



ALTERNATIVES FOR THE COAST

A Staff Report

New Jersey Department of Environmental Protection

~~Division of Marine Services~~

Office of Coastal Zone Management

P.O. Box 1889

Trenton, New Jersey 08625

October 1976

Let's protect our earth



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PREFACE

On September 19, 1976, Commissioner David J. Bardin submitted to the Governor and Legislature the alternate environmental management strategies for the coastal area required by Section 16 of the Coastal Area Facility Review Act (CAFRA) of 1973.

As the Commissioner's submission indicated, the alternate strategies need to be refined, analyzed, expanded, and debated. This staff report provides the context and agenda for this debate and discussion.

Over the next year, the Department will prepare a management program for the entire coast, to be submitted for approval of the U.S. Secretary of Commerce under the Coastal Zone Management Act of 1972. The state-wide coastal management program will also include the final environmental management strategy required under CAFRA, for that portion of the state.

Section I of this report sketches the background of coastal zone management in New Jersey and raises the question of the proper scope of activities that should be included within the coastal zone management program. Section II outlines the implications of the alternate strategies presented by the Commissioner. Section III states twelve fundamental principles that helped shape the alternatives in this report. Section IV offers policy alternatives on selected coastal resources and selected land and water uses in the coastal zone. Section V highlights alternatives for the appropriate geographic extent of New Jersey's coastal zone management program. Section VI points to the alternate ways of making public decisions on coastal resource management. The concluding section outlines the next steps in the preparation of a management program to shape the future of the coast.

This report is the "tip of an iceberg". Separate staff reports provide the analytical and descriptive basis and background for the summary statements presented here on coastal resources, land and water uses, and boundaries. These staff working papers will be available, for review and comment, to people interested in specific topics.

This general report aims to indicate, for public discussion, the scope of issues under consideration and present an initial set of policy alternatives for debate. Gaps may exist in the alternatives presented here; this document is intended to encourage the public to help identify those gaps and suggest additional policy alternatives. This report aims to open the debate.



STATE OF NEW JERSEY
DEPARTMENT OF ENVIRONMENTAL PROTECTION
DAVID J. BARDIN, COMMISSIONER
P. O. BOX 1390
TRENTON, N. J. 08625
609-292-2885

Submission of Alternate Environmental Management
Strategies for New Jersey's Coastal Area

To the Honorable Brendan Byrne, Governor,
and the Legislature of the State of New Jersey

Extraordinary incidents plagued the Jersey Shore this summer and heightened public concern for our prized coastal resource. The incidents prompt anxious questioning: "Do our officials care?" "Does New Jersey have a strategy to protect the shore?" Similar questions arise about our urban coastlines.

Fish, lobsters and other ocean bottom creatures suffocated for lack of oxygen as a vast algae bloom in the deeps died and decayed over hundreds of square miles of ocean floor. The unusual mass of algae had grown explosively, fed by pollutant nutrients, channelled by ocean currents and favored by abundant sunshine. An early hurricane broke through dunes and inflicted millions of dollars of property damage, and nearly ravaged far more. Ocean surf and bay beaches were befouled by garbage, dead sponges and sewage. One municipality resisted closing a beach contaminated by its own malfunctioning sewage plant.

Other coastal environments were also under attack. An oil spill polluted the tidal portion of the Hackensack River and the salt marshes of the Meadowlands. A huge landfill was ordered to cease accepting noxious liquid and chemical wastes in order to halt seepage into the tidal Raritan River. Tidal waters, sediments and fish came under scrutiny for PCB's, Kepone and other toxic chemicals.

The Atlantic Ocean receives pollution not only from the shore but from all the urban and suburban areas on New Jersey and from neighboring states. Yet our existing research and governmental institutions provide little understanding of that marine environment and its teeming resources.

Part of the answer lies in the State's continued drive, with federal assistance, for better sewage treatment facilities that will improve all effluent quality, end all discharges into the back bays, cut out ocean dumping of sewage sludge and eliminate

three quarters of the organic municipal sewage wastes that reach the ocean. The cost of construction underway in New Jersey already exceeds one billion dollars, but few new plants are yet in operation. The State and the City of Camden have announced the first full-scale pilot project to turn that City's sludge into useful compost instead of dumping it into the ocean. The momentum achieved throughout most of the State depends on authority for more federal funding proposed by the Water Pollution Control Bill, S.2170, now in Senate-House Conference.

Congress recently enacted the 200-mile fisheries law with comprehensive regional management of migratory species. Congress is about to complete the offshore leasing reform and oil spill liability bill, which faces a possible Presidential veto.

Federal auction of Atlantic Ocean oil and gas leases has brought nearer the possibility of oil pipelines and facilities on our beaches, bays, wetlands, pine barrens and coastal plain ground water aquifer. Debates continue on nuclear power, liquified natural gas terminals and oil and chemical port facilities.

A study commission is hearing conflicting public testimony on access to the beaches. Congress has authorized land acquisition assistance for shoreline access.

Operation Sail drew multitudes to the urban water's edge. The first portion of Liberty State Park, and other projects around the coast from Burlington to Bayonne, rehabilitated derelict waterfronts for public access and recreation.

These actions, incidents and concerns illustrate the need for a coherent set of strategies for coastal management and protection in New Jersey. The water's edge is a limited, coveted and fragile resource--a resource liable to severe damage by mismanagement of either the marine environment or the adjacent hinterland.

History amply demonstrates man's capacity to mismanage, pollute and blight the coastal resource. To what extent can New Jersey do better than we have done in the past? For what purposes shall we manage each of our various coastal zones?

Our goals and strategies should speak to at least twelve topics:

Quality and pollution of the coastal and tidal waters.

Erosion and flood hazards.

Wildlife management, including marine fisheries.

Wilderness and natural areas.

Protection of ground water supplies in the coastal plain.

Public access and privacy.

Recreation and tourism.

Energy facilities and other industrial potential.

The coastal cities.

The existing housing stock.

New housing development.

Transportation systems.

The following alternative strategies for coastal management of one or more sectors of the coastal area are under consideration by the Department and will be evaluated during the coming year:

Encourage recreation and tourism development and use of the coastal area.

Provide water access for uses dependent upon it.

Encourage suburbanization.

Encourage other residential development.

Maintain relative privacy of existing houses and other facilities.

Discourage residential sprawl.

Preserve wilderness and natural areas.

Exclude and restrict number of energy facilities.

Set aside sites or corridors for energy facilities (a) to meet New Jersey needs and (b) to contribute to national needs.

Encourage industrial development.

Discourage industrial development.

Reversal of past development patterns by redevelopment, rehabilitation or discouraging rebuilding of damaged structures.

Conservation of water supplies and energy.

Protection of land and sand from erosion.

A single, uniform strategy for the coast is unlikely to respond fully to the diverse purposes the coast should serve.

Different strategies will be appropriate for different parts of the coast. A coherent set of strategies must be fashioned from choices among the broad alternatives outlined here.

The alternate strategies posed here are stark and simplistic. Over the next year the Department will refine these strategies, analyze their implications, explore their advantages and disadvantages, and submit these reports to public scrutiny and debate. We have already published the first such report on Interim Land Use and Density Guidelines. Selection of the final coastal management program for New Jersey depends upon public debate on these strategies and specific policies to realize the vision chosen for the coast.

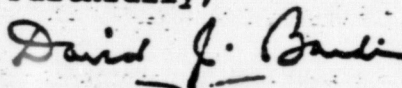
Incredible diversity characterizes our coast today. The coast is not just the "Jersey Shore." Stretching from the New York State border, along the Atlantic Ocean, and up the Delaware River to the head of tide at Trenton, the coast includes tidal waters, wetlands, beaches, parks, rural area, urban waterfront, energy facilities, ports, and homes for millions.

The coast is a special place, as recognized by certain State laws -- riparian statutes, the Wetland Act of 1970, and the Coastal Area Facility Review Act (CAFRA) of 1973 -- and the federal Coastal Zone Management Act (CZMA) of 1972.

The foregoing alternative environmental management strategies are submitted now as required under Section 16 of the Coastal Area Facility Review Act, and as broad alternatives for the entire coast, both the CAFRA part of the State and the more urban coastline potentially affected under the federal Coastal Zone Management Act, as well as the state riparian laws.

Public actions or inaction will shape the future character of the coast. The choices are before us.

Faithfully,



David J. Bardin
Commissioner

September 19, 1976

Exclude and restrict number of energy facilities.

The development of certain additional energy facilities, such as nuclear generating stations and refineries, would be excluded from the coastal zone, or only a limited number of facilities would be authorized.

Set aside sites or corridors for energy facilities (a) to meet New Jersey needs and (b) to contribute to national needs.

Specific sites would be identified for OCS staging areas, electric generating stations, etc., and corridors would be defined for pipelines and transmission lines.

Encourage industrial development.

Development of industrial, processing and manufacturing facilities would be encouraged, in preference to other land uses, such as residential or recreation. This would apply particularly along the urban waterfront in north Jersey and along the Delaware River.

Discourage industrial development.

Further industrial development would be halted, forcing new or expanding industries to locate inland.

Reversal of past development patterns by redevelopment, rehabilitation or discouraging rebuilding of damaged structures.

Damaged buildings on barrier islands would not be rebuilt after hurricanes and coastal storms. Elsewhere, low density development would be replaced by higher density development.

Conservation of water supplies and energy.

Development affecting major aquifers, such as the Pine Barrens, would be discouraged. Mass transportation, better insulation and other energy conservation practices would be encouraged.

Protection of land and sand from erosion.

Soil erosion measures would be vigorously enforced for all development and soil disturbance activities. Sand movement along the shoreline would be managed by construction of shore protection structures.

III. GUIDING PRINCIPLES

Several basic principles guide the formulation of the alternatives policies for the coast presented in Section IV. These principles establish fundamental attitudes toward coastal resources, appropriate land and water uses of coastal resources, how these resources are used, and how public decisions are made on the use of the coast and its resources.

Marine Environment

The productivity of existing marine resources should be maintained or improved. For example, the quality of our bay and ocean waters and highly productive areas such as oyster and eel grass beds, spawning, and feeding areas require vigilant protection.

Shoreline and Urban Waterfront

The water's edge where the land meets the sea -- the urbanized waterfront and the less developed and rural shoreline -- should be devoted only to activities that depend upon direct water access and require a shoreline or waterfront location.

Coastal Land Environment

The valuable upland air, land, and water resources of the natural environment of the coast should be respected and protected.

Coastal Appearance

The design of coastal land uses should respect and reinforce the visual characteristics of diverse parts of the coast. The mix of scenic resources of the New Jersey coast, including large bays, barrier beaches, the ocean, rolling forested hills and mighty urban rivers with built-up waterfronts, should be maintained.

Built Environment

Orderly, balanced, residential, commercial, and industrial development should be accommodated in the coast, in settlement patterns that are economically efficient and respect the natural environment. Development of hazardous areas should be avoided. Cultural resources should be preserved.

Public Access

Activities that increase public access to the coast should be encouraged and existing public rights of access to the coast should be protected.

To carry out these principles, the concepts which follow guide how coastal resources are used.

A. Ocean Resources: Mineral

Issue

Ocean mineral resources such as oil and gas and sand and gravel are thought to lie off the coast of New Jersey, but these are not exploited at the present time. The quantity of resources and best methods of extraction are not fully known. The potential for environmental harm resulting from their extraction is great. Concerns are for onshore as well as offshore impacts.

Policy Alternatives

A. Oil and Gas

State policies concerning OCS oil and gas development will be viewed in the light of the national interest and marine resources. Many state policy alternatives have apparently vanished with the recent Supreme Court ruling that the Federal government controls all offshore water beyond the three mile limit. Therefore, the State could concentrate on those oil and gas exploration-related activities proposed for the nearshore (3 miles or less) waters and onshore sites. The State also should carefully consider any action which would lead to massive or chronic oil spills on important recreation beaches, estuaries, or wildlife habitat.

1. The State could seek to establish a system of financial compensation for economic or environmental damage from offshore oil spills or uncontrolled chronic discharges washing ashore. This would include compensation to commercial fishing operators. Careful monitoring of pollution sources would be essential. Monitoring could be accomplished through cooperation with the U. S. Coast Guard.
2. The State could assume a strong role in delineating oil pipeline corridor routes and landing sites. Factors in establishing routes should include: proximity to important recreation beaches, wildlife refuges, shellfish and fin fishing areas, tidal wetlands destruction, and secondary onshore impacts. The State could also assist offshore oil companies in finding suitable industrial sites which would have least damaging environmental or social effects. Full burial of all pipelines at least three feet, design of bottom protrusion which would not foul fishing gear, and adequate and properly maintained surface markers of submarine obstructions could reduce potential conflicts, and compensation law suits between oil and fishing industries.

3. The State could provide greater financial assistance to public and higher education in marine resources research and training programs. These programs could focus on industries dependent on marine resources in New Jersey. These would include offshore oil and gas, fishing, and tourism.

B. Sand and Gravel

Offshore sand and gravel mining has potential adverse environmental impacts. These might be reduced if the following steps were taken:

1. Offshore sand mining, if and when proposed, could be directed to areas of little value to surf clam, lobster, sea scallop, and sport fishermen.
2. The possibility of mining of previously disposed dredge spoils could be explored. This could present an alternative to mining in natural land areas, however, dredge spoils may be contaminated with toxic agents and therefore of limited use.
3. Careful consideration and site selection could be given to sand and gravel mining in the important surf clam nursery areas less than 1.5 miles from shore. Sand and gravel mining should be prohibited adjacent to shorelines with a history of beach erosion, unless the sand is used for beach nourishment projects.
4. Sands derived from maintenance dredging of channels and inlets could be sold for industrial uses, rather than used for filling of valuable wetlands.

Q. Energy

Issue

Many of the new and proposed facilities that process, produce and transport energy, such as offshore and onshore nuclear plants, liquified natural gas (LNG) operations and OCS related oil and gas facilities, have been designated for the coastal zone because of their high dependence on water locations for docking, loading, transfer and coolwater processing operations. There are inherent land use and environmental conflicts in siting such energy facilities in coastal areas of New Jersey which serve as a recreational resource for millions of state and out-of-state residents. Unless carefully planned and sited, prospective energy facilities could wreak irreparable harm on the state's most precious natural assets.

Policy Alternatives

The state could strive to secure adequate, safe reliable sources of energy consistent with maintaining public health and enhancing the quality of life and environment.

The need to maintain a diverse energy fuel base is dictated by the uncertainties affecting both fossil fuel and nuclear production as they relate to health and environmental impacts, price rises, Federal policies and foreign embargos, as well as to the speed with which solar energy production can be brought on line. Federal involvement in energy matters covers nuclear power, oil and gas production and, of particular importance in New Jersey, prospective Outer Continental Shelf (OCS) development. While the state cannot stop the Federally initiated activity, it can control the siting of facilities in at least some parts of the state.

Siting impacts from energy facilities are not uniform. While OCS related development could have a pervasive effect in the region where it is located, nuclear power and LNG operations are not growth stimulators.

General policy alternatives, issues and implications relating to OCS, nuclear and LNG operations are set forth in the following section. Specific statements follow in separate sections.

1. The state could diversity its energy options and encourage a mix of energy technologies to avoid becoming too dependent on any one technology due to the potential problems inherent in each option, such as nuclear accidents, gas curtailment, LNG tanker accidents, and oil dependency.
2. The state could draw up an energy plan specifying energy flows in the state and identifying future needs. Criteria for siting energy facilities could be developed and suitable sites identified.

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2. The state could draw up an energy plan specifying energy flows in the state and identifying future needs. Criteria for siting energy facilities could be developed and suitable sites identified.

At present energy decisions are made by utilities and industries applying for permits to build new facilities based on data and demand forecasts to which the public (and state) is not privy. The environmental, social, and economic impacts of energy facilities indicate a need for an independent and comprehensive analysis of energy needs.

3. Energy facilities could be directed towards existing industrial locations away from the oceanfront. An exception could be made for economically troubled Atlantic City.

To protect the undeveloped parts of the state's coast, which serve as a regional, state and national resource for millions, energy facilities could be sited outside the coastal area to the extent practicable. Where no alternative exists, the facility or facilities could be clustered in one discrete location to avoid random sprawl of these facilities.

Directing new energy facilities to existing industrial areas outside the CAFRA Area, around Raritan Bay and Delaware River which have vacant land and available infrastructure and manpower, would serve to boost the declining economies of these areas and add jobs. At the same time, these areas possess the infrastructure and transportation systems to distribute the new energy resources. Atlantic City is an oceanfront urban city whose economic base is in decline. It could be exempted from this alternative policy because it has vacant land, an existing infrastructure and an available labor force.

4. In drawing up siting criteria DEP could identify:

a. those facilities which are:

- i) absolutely coastal dependent (LNG facility docks)
- ii) peripherally dependent such as (nuclear generating plants)
- iii) not at all dependent (refineries)

b. facilities which serve as stimuli for growth and conversely those which do not.

c. ecologically sensitive or fragile areas and densely populated recreational areas of the coast where no energy facilities will be allowed.

5. The state could promote energy conservation. It²⁷⁰ could provide incentives for installation of solar heating and cooling devices; accelerate implementation of the Uniform Construction Code and provide incentives for its adoption. It could encourage and provide incentive for industries to recycle waste heat through cogeneration. It could at the same time apply for research and development grants for conservation and demonstration grants from Federal Energy Administration (FEA) and Energy Research Development Administration (ERDA) to test various solar and other technologies. While conservation may not eliminate the need for power plants in the future, it can reduce their number.

Outer Continental Shelf (OCS) Oil and Gas

Issue

The central issue is how to accommodate OCS related industry and facilities without degrading the quality of the state's waters and coastal environment. New Jersey supports OCS activity, if it is conducted in a manner in harmony with the natural environment.

The Department of the Interior's accelerated leasing program, as affirmed by federal courts, requires that the State work to minimize potential adverse onshore impacts resulting from the offshore exploration. Oil and gas drilling do not pose the health and public safety hazards associated with the nuclear and LNG operations. Unlike nuclear and LNG operations, however, they could have pervasive beneficial and adverse effects on the economy by attracting secondary gas and oil service and manufacturing enterprises. These facilities, in turn, could induce tertiary impacts and exert demands on infrastructural and community facilities.

Policy Alternatives

1. The State could support OCS development consistent with protecting its unique environment and maintaining a viable tourist economy in the coast.
2. OCS facilities could be located in or near existing industrial areas which have suffered blight, unemployment and decline, and are in need of redevelopment.
3. OCS activities could be directed away from popular beach resorts, wetlands and barrier beach islands.
4. DEP could identify OCS related facilities which are:
 - a. coastal dependent (staging areas, docks, storage yards)
 - b. peripherally dependent (pipeline terminal, tank farms, gas processing plants)
 - c. not at all dependent (refineries)

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Location adjacent to coastal areas would be based on this identification.

5. The State could establish an advisory board made up of industry, Federal, state and local government representatives and members of the fishing and tourism industry. Such a board would serve as a problem solving agency providing a mechanism for industry and local representatives to meet and communicate on matters of mutual interest.
6. The state could coordinate OCS-related activities so that the Department of Labor and Industry will have early notification of pending applications and be able to furnish the manpower and training skills which may be required as the facilities become operational. This could ensure that state residents benefit from the OCS program.
7. Expansion of existing refineries could receive priority over construction of new ones. Where no expansion alternatives exist, new refineries could be sited away from beaches and recreational areas and as close to existing pipeline networks and distribution systems as possible.
8. OCS resources could be brought ashore by pipeline, along rights-of-way to be established by the Department of the Interior and the State.

Where pipelines are economically infeasible, the State could explore the economies of building a deepwater port within the 3 mile territorial limit with a pipeline (smaller in dimension and shorter than the ones which would come from the leased tracts) connecting the port to the shore. This would reduce the number of tankers coming into existing ports and the probability of associated collisions and spills.

Nuclear Energy

Issue

Nuclear energy poses significant health and public safety hazards which have not been fully resolved. The Federal Nuclear Regulatory Commission, the lead agency on nuclear energy and a supporter of its use, offers little guidance to the states concerning siting criteria.

Nuclear generating facilities are traditionally sited away from population centers and are not growth stimulators by themselves. The building activity that has occurred around the Oyster Creek plant in Ocean County, located in the heartland of the coast's recreational area, has become a State concern and has led to a temporary moratorium on further building around nuclear facilities in the state.

works with similar programs in neighboring states through the Mid-Atlantic Governor's Coastal Resources Council (MAGCRC) and meetings with representatives of coastal zone management programs of other states.

State-Federal Interaction

State-Federal interaction under the federal Coastal Zone Management Act is defined in two sections of the Act. Section 307, entitled "Interagency Coordination and Cooperation", is also known as the "federal consistency" provision. Section 306(c)(8) and section 307(c)(3) contain the "national interest" provisions. Both of these provisions establish a complex system of federal-state relations with respect to coastal zone management. The goal of these provisions is to insure that the national interest is included in a particular state's management program and that federal agencies conducting activities in the coastal zone will carry out their responsibilities to the maximum extent practicable with federally approved state management programs.

The Coastal Zone Management Act of 1972 as amended seeks the accommodation of state and Federal interests in the coastal zone by three sets of statutory provisions. The first set requires cooperation between state and federal agencies in the development of a state's coastal zone management program. The second set requires that, within limits, Federal actions be consistent with an approved state program. The third set, consisting of only one provision, requires the Secretary of Commerce to include in his annual report to the Congress mention of any inconsistencies between Federal activities and approved state programs. Together, these provisions are called the "Federal consistency" provisions of the Act.

Since New Jersey has not yet submitted a management program for approval by the Secretary of Commerce, the federal consistency provisions have not yet been triggered. However, the New Jersey Office of Coastal Zone Management has been working with federal agencies to determine the provision's applicability to New Jersey.

Another important issue in state-federal interaction is the extent to which federal lands are excluded from the provisions of approved state management programs. Recently, at the request of the National Oceanic and Atmospheric Administration, the Department of Justice issued a memorandum of law which interpreted the scope of excluded federal lands more broadly than state and NOAA officials would have desired. New Jersey will seek further clarification of this issue in the coming year.

The Federal Coastal Zone Management Act of 1972 also requires that the national interest be considered in developing state management programs. Section 306(c)(8) states that the management program must provide for "adequate consideration of the national interest involved in the siting of facilities necessary to meet requirements which are other than local in nature". The national interest also is subject to definition. Examples of facilities which may be covered by the provisions include defense

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installations and energy and port projects. This section of the federal act is not designed to force state acceptance of "national interest" facilities into their plans, but rather to insure that such facilities are not arbitrarily excluded from a state management program.

The national interest plays an important role in the federal consistency provisions of the act. Section 307(c)(3) provides that if the federal agency's activity is necessary in the interest of national security, the Secretary of Commerce may allow such activity notwithstanding the inconsistency with state programs.

Public and Governmental Involvement

Regardless of the governmental structure chosen to implement coastal zone management, public involvement will be an important key to success. The federal Coastal Zone Management Act, in fact, requires that a State provide "an opportunity for full participation in the development of its management program to all public and private agencies and organizations which are liable to be affected by, or may have a direct interest in the management program".

The involvement of the public is designed to establish lines of communication between the State coastal planning agency and the many affected municipalities, groups and individuals. The goal is not to create a town meeting-type voting process. The goal instead is for the public to articulate and defend the issues and problems with which they are familiar. The role of the state is to attempt to balance these often conflicting interests in a manner beneficial to all New Jersey residents and users of the coast.

The first major opportunity for public involvement in coastal zone management came in the spring of 1975 when open meetings were held in Toms River and Trenton to seek consensus on the environmental data DEP would use in coastal planning. DEP was assisted in those meetings and in several follow-up workshops by the American Arbitration Association. The result was agreement on nine categories of data: Bathymetry, Flood Areas, Geology, Groundwater, Land Use, Slope, Soils, Tidal Wetlands, and Vegetation. Much of this information was included in the Inventory of the New Jersey Coastal Area submitted to the Governor and Legislature September 19, 1975.

The major focus for public participation in the past year was preparation of the Interim Land Use and Density Guidelines for the Coastal Area. Department staff shared preliminary drafts and held meetings with County Planning Directors and leaders of several statewide builders and environmental groups. Following publication of the guidelines in July, DEP held open evening meetings in Monmouth, Ocean, Atlantic, Cape May and Cumberland counties. At those meetings, DEP staff answered questions and listened to comments on the Guidelines and a wide range of coastal and environmental issues.

Since CAFRA was enacted, a more specific form of participation has been provided by the public hearings held on all CAFRA permit applications. These hearings, held in the vicinity of

6624
The present document marks the two-thirds point in preparation of a management strategy for New Jersey's coastal zone. By September 1977, a completed strategy will be presented to the Governor and Legislature. 2794

DEP's planning work under CAFRA will be increasingly linked with similar efforts for the Federal Coastal Zone Management Act (CZMA). Under that statute, the Governor of New Jersey must submit a program for the coastal zone either by September 1977 or, under the new 1976 Amendments to the Act, during the year following. While the boundaries of the two plans will differ, the issues of concern and the time schedules are sufficiently similar that much of the work will be united.

In the next year, efforts will be focused on correcting, refining, and supplementing the material in this report. DEP will place great emphasis upon obtaining outside comments through a wide dissemination of this document and other supporting reports to Legislators, municipal and county officials, interest and civic groups, and interested individuals.

DEP has prepared detailed discussion papers on each of the nineteen resources and uses described in Section IV. These papers combine discussion and analysis of the many issues raised by each topic. The issues are complex and the papers may well suffer from omissions or errors. Like this document, however, they are intended for widespread discussion and debate.

In the Fall and Winter of 1976, DEP will convene topical workshops on many of the issues described in Section IV. These meetings will be open to the public, and people with identified interest or expertise in particular issues will be specifically invited. The Workshop discussions will hopefully provide information valuable for coastal planning.

DEP is also initiating contractual studies to provide additional information. The Department received a supplemental grant to study the onshore impacts of OCS development. Half of this grant has been channelled directly to the counties. Also, the feasibility of storing coastal environmental data on a computer in a format accessible to citizens unfamiliar with computer technology is being explored. DEP will also initiate contractual studies on an economic analysis of coastal issues, estuarine environment, recreation and commercial boating and facility development, salinity in the Delaware River, and coastal geomorphology.

During the next year, the strong relation between the CAFRA permit process and the planning process will continue. DEP has already gained significant experience from permit applications, and shaped coastal policies from the experience with the 130 decisions on applications to date. The Interim Land Use and Density Guidelines for the Coastal Area were, in part, a codification of the evolving permit policies. This unique source of policy development will continue.

From this stream of analysis, debate and discussion will evolve the coastal zone management program for New Jersey.

Pages 2796 to
Pages 2811
are not included
in this
appendix

2812

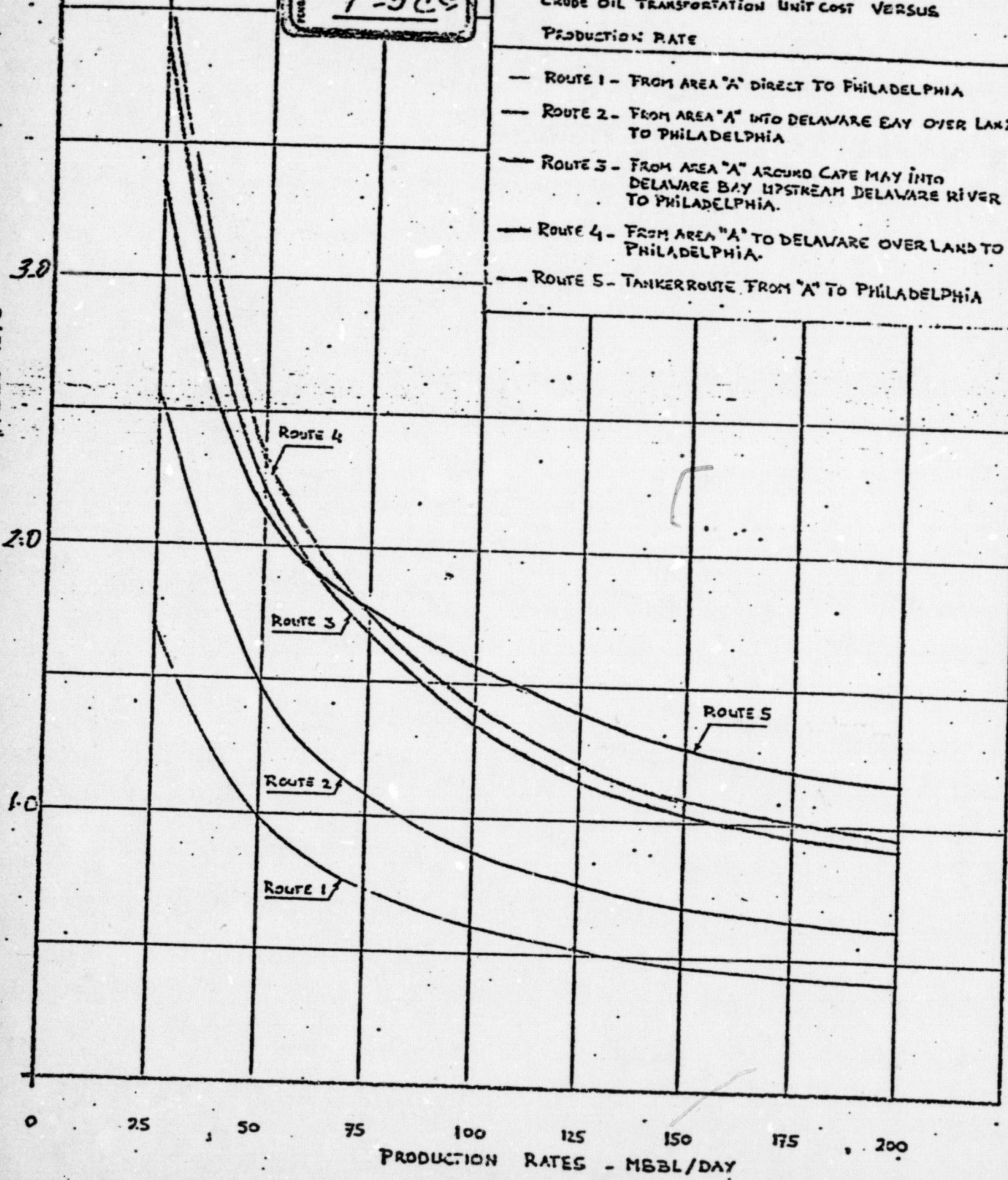
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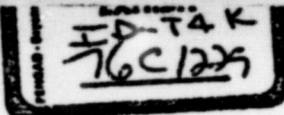
DEFENDANT'S
EXHIBIT
T-504

AREA "A" TO PHILADELPHIA

CRUDE OIL TRANSPORTATION UNIT COST VERSUS
PRODUCTION RATE

- ROUTE 1 - FROM AREA "A" DIRECT TO PHILADELPHIA
- ROUTE 2 - FROM AREA "A" INTO DELAWARE BAY OVER LAND TO PHILADELPHIA
- ROUTE 3 - FROM AREA "A" AROUND CAPE MAY INTO DELAWARE BAY UPSTREAM DELAWARE RIVER TO PHILADELPHIA
- ROUTE 4 - FROM AREA "A" TO DELAWARE OVER LAND TO PHILADELPHIA
- ROUTE 5 - TANKER ROUTE FROM "A" TO PHILADELPHIA





1 America be in a better economical position to "Put
2 American Back To Work."

3 Thank you.

4 JUDGE MOORE: Any questions?

5 Thank you, sir.

6 I'll call again on Diane Graves. Is she
7 here?

8 I presume not. I'll call again on
9 Mr. Zedrosser.. I see no one coming.

10 So, Mr. Jarmer. Elwood Jarmer.

11 Go ahead, Mr. Jarmer.

12 MR. JARMER: Mr. Chairman. My name is
13 Elwood Jarmer. I am the Director of the Cape May County
14 Planning Board. With me today is a member of our Planning
15 Board, Mr. Fred Long and a member of my staff, Mr. Robert
16 Myers. We thank you for the opportunity of appearing
17 before your committee to present our statement. This
18 statement is the official policy of the Cape May County
19 Board, elected governing body of the County, the County
20 Planning Board and the Cape May County Environmental
21 Council. I will submit copies of the Freeholders and
22 Planning Board resolutions and a full copy of this state-
23 ment after my presentation. For purposes of time, I'm
24 not going to read the whole thing, but try to paraphrase
25 certain sections.

1. Generally, the Draft Environmental Impact
2 Statement on the proposed OCS Sale Number 40 is a great
3 improvement over the so-called "generic" statement on
4 the proposed accelerating leasing program. However, our
5 two prime areas of concern, oil spillage and induced
6 onshore industrial development, remain. Several
7 specific statements in the draft merit comment, particularly
8 those attempting to quantify the economy of Cape May
9 County.

10 The statistical data is misleading and
11 incorrect. For example, receipts from camping and trailer
12 categories should be \$3,000,000, not \$1,200,000; income
13 from vacation homes totals \$54,000,000, not \$2,000,000;
14 total tourism receipts for the County should total in
15 excess of \$120,000,000, not \$33,000,000. The importance
16 of these errors in the baseline data has to be corrected
17 because the conclusions are somewhat different, if you
18 correct the data.

19 Another example is that local property
20 taxes generated by tourist investment in 1973 exceeded, or
21 were close to \$20,000,000, not \$700,000.

22 To be clear, tourism in New Jersey is the
23 State's second largest industry. That misunderstanding
24 is expressed again on page 555 of Volume 1 - "The New Jersey
25 shore resort areas experienced the first significant

1 increase in vacation activity in many years during the
2 1974 season". Well, in fact, tourist retail sales
3 have increased over 500% since 1950 at a steady rate of
4 increase over the years.

5 The implication in your report is that
6 the expansion of the industrial base of non-industrialized
7 counties is desirable. Again, the statement is technically
8 true in the broad perspective but the fact is that Cape
9 May County and other tourism oriented areas seek only
10 certain specific types of non-smoke stack industries to
11 complement their seasonal resort economies. For example,
12 electronic assembly facilities, colleges and marine
13 research laboratories would, in our view, augment the
14 seasonal resort economy; OCS staging areas, gas processing
15 plants, and refineries, would not.

We disagree with the statement "A county
dependent on the tourist industry, for example, in expanding
its industrial base would lessen its dependence on outside
areas and vulnerability to the fluctuations and uncertainties
associated with the tourist industry." The simple truth is
that tourism and heavy industry cannot peacefully coexist.

Your EIS continues to state, "Many of the
problems associated with an unstable, unpredictable and
limited economic base can be avoided by widening the
industrial base and providing the economy with more certain

1 earning power..." In fact, the opposite is true. During
2 the summer of 1974, while the nation and state were
3 suffering through a severe recession, the County tourist
4 industry had one of its best years. The lesson in this
5 could be that the expansion of the economic base through
6 manufacturing and heavy industrialization may, in some
7 areas, increase the problems it is trying to solve.

8 The resort industry of Cape May County and
9 the coastal areas of New Jersey is simply not brought to
10 its knees by cyclical periods of inflation and recession
11 as are other heavy industrialized based economies.

12 Even if the County of Cape May were to
13 heavily industrialize as the result of OCS activity, what
14 kind of an economy could we expect in 20 years when the
15 mid-Atlantic OCS is depleted of hydro-carbon reserves?
16 Our prosperous resort economy and the high quality of
17 natural environment which abounds in Cape May County is
18 unlimited in time and gross dollar potential only if left
19 unscathed by heavy industry. Just as the Nation needs
20 energy, the Nation also needs recreational opportunities
21 and Cape May County and the Jersey Shore have and should
22 be allowed to fulfill this need. Once our fragile
23 environment upon which the resort economy depends is
24 destroyed, it can never be recreated by man.

25 I would add, parenthetically, that this is

1 not a parochial and self-interest. Cape May County is
2 enjoyed by millions of people in the New York, Philadelphia
3 metropolitan area and the loss of the environment and the
4 recreational opportunities at the Jersey Shore could be
5 catastrophic to the metropolitan area.

6 I'll summarize the next portion of this
7 statement by saying that refineries are a possibility.
8 Your data indicates that refineries are a possibility in
9 your earlier reports and also hinted at in this report.
10 We feel that refineries should not be located in the
11 Jersey Shore area.

12 Another issue raised in the Draft Environ-
13 mental Impact Statement is the possibility of additional
14 near-shore drilling. Let me summarize by saying, the
15 County will resist such further proposals as vigorously
16 as we resisted this, since the further closer drilling
17 would only aggravate some of the problems that your EIS
18 says could occur in this sale.

19 While we endorse the efforts of the Interior
20 Department to ameliorate the potential negative impacts
21 of OCS activity through the OCS operating orders and
22 special stipulations, we feel that they are inadequate
23 protective devices for the concerns we have for our County.
24 If the opposition to Sale 40 is unsuccessful, we will
25 insist that stipulations and OCS operation orders as they

1 affect Cape May County be substantially modified and
2 enlarged. As a minimum, the proposed lease stipulation
3 regarding designated pipeline corridors should be written
4 to provide for consistency of the BLM Plan and the affected
5 State Coastal Zone Management Plan and any adopted
6 regional plan designating pipeline corridors. Onshore
7 support and processing facilities should also comply
8 with these plans.

9 Lease stipulations should also provide
10 for regional participation in the two-phase pipeline
11 corridor study cited on page 356 of Volume II. The
12 importance of coordinating this study at all levels is
13 made clear on page 228, and I quote - "The general
14 locationlocation of many of the facilities which would
15 be required onshore as a result of the proposed sale
16 would be a function of where pipelines are allowed to
17 come ashore." This is particularly important in the
18 context of water availability. Recent studies by the
19 State of New Jersey and the Cape May County Planning
20 Board indicate that water availability in Cape May County
21 will be limited in the future. With gas processing
22 facilities consuming over 5,000,000 gallons per year,
23 that impact on tourism is significant. For example, one
24 gas processing plant in Cape May County, at that rate of
25 usage, would consume as much water as 56,000 summer

1 visitors.

2 As refineries consume 40 gallons of water
3 for each barrel of crude oil processed, the impact of a
4 refinery would be devastating in terms of water with-
5 drawal alone.

6 In addition to these stipulations regarding
7 pipeline corridors, staging and processing facilities,
8 we recommend revisions to others regarding such items as
9 traverse any ocean dumping sites, lightering, air quality,
10 distance of onshore OCS activities in tourist and recrea-
11 tion areas and also oil contingency plans.

12 We heartily endorse the concept of a
13 super fund to indemnify our County in the event of a
14 spill.

15 Essentially, the negative impacts of OCS
16 Sale Number 40 are crystalized in two issues: oil
17 spillage and induced onshore industrial development.
18 Through this Environmental Impact Statement, the Federal
19 Government has told the residents of the Mid-Atlantic
20 region that they won't be responsible for oil spill
21 damage and they can't be responsible for onshore develop-
22 ment.

23 In our comments on the draft generic
24 Environmental Impact Statement on OCS leasing, we said
25 that the Federal Government should not sell OCS lease

1 sale areas and ignore the consequences. We stand by
2 that statement. We will continue to resist to the fullest
3 extent possible the attempt to industrialize, urbanize
4 and destroy the environment and resort economy through
5 federally authorized OCS activities. The Cape May
6 County Planning Board therefore urges you to withhold
7 OCS Sale Number 40.

8 And I would add that we would hope that
9 the final EIS as prepared by your Department would reflect
10 a number of the items that we have presented in this
11 position paper.

12 Again, I appreciate the opportunity to
13 appear and would answer any questions that you might have.

14 MR. TRUESDELL: Mr. Jarmer, we would
15 appreciate any reports that you might have to back up
16 some of the tourism -- we used other sources, obviously.

17 MR. JARMER: I understand. Yes. We will
18 provide...there's a member of your staff...anyway, after-
19 ward, I will provide you with an address and we will
20 communicate with them.

21 MR. KELLY: Mr. Jarmer, do you have...you
22 asked us at the end to withhold the sale. Do you have
23 some proposal to make...is there a time factor? What is
24 it that you're suggesting?

25 MR. JARMER: We would say that the basic

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1 problems that we see with the lease sale, that being,
2 adequate proposal for protection, oil spills, and adequate
3 stipulations should be specified. Plus, the importance
4 of the resort economy should be clarified in your state-
5 ment. And I think these are important before you proceed
6 further with any decision to lease.

7 MR. KELLEY: The question of Federal
8 regulation and/or lease stipulation relative to pollution
9 that's sort of do-able, achievable. I wonder if the
10 Cape May County feels that it has enough authority in
11 its police power, zoning power, that if an oil company
12 comes to it with a request to construct a refinery or
13 bring pipelines ashore, that given your mandate from the
14 citizens of the County that you can exercise that
15 particular police power?

16 MR. JARMER: As I mentioned in the state-
17 ment, we would attempt to so do and utilize our police
18 power and our planning powers, municipal, County and
19 hopefully, the State Coastal Zone Management Act to the
20 fullest extent. That is not to say that there won't be
21 areas that will be excused from local regulations because
22 of some overriding Federal need. I understand there are
23 some regulations on gas, for example, where Federal
24 regulations usurp local regulations. So, what we're
25 looking for is for the Federal government to recognize

1 this and in a stipulation indicate that they will not be
2 overriding if some crisis appears in the future, a local
3 regulation and that the stipulations would further
4 clarify the Federal position on that.

5 MR. KELLY: The Coastal Zone Management
6 Act requires that--that in the event of national interest
7 that there will have to be a usurpation, but that's such
8 a way-out prospect. I was just wondering if you felt that
9 from a state-local government standpoint that you had
10 adequate laws to provide the authority to exercise the
11 will that you are discussing?

12 MR. JARMER: I can speak for County govern-
13 ment. The County government does not have land use
14 control. Local government, municipal government does to
15 the extent that that's used remains to be seen. Local
16 government will have to respond to that. To the extent
17 that the Coastal Zone Management Act is used in the best
18 interest of Cape May County remains to be seen. We hope
19 so. We have been working with the State very heavily in
20 the development of their Coastal Zone Management Program.

21 MR. LONG: Mr. Kelly, my name is Frederic
22 Long. I am Vice Chairman of the Cape May Planning Board.
23 I just might add to Mr. Jarmer's response to your question,
24 we consider as our statement indicated the Federal govern-
25 ment a rather formidable adversary in this procedure, and

1 when joined with the energy industry in the country, this
2 makes it even more formidable.

3 I think that our statement stressed that
4 the consequences of this OCS development which you're
5 initiating, we will have to bear and live with and, as
6 Mr. Jarmer indicated, our resources in dealing with this
7 problem are not as strong of either those of the Federal
8 government or as strong as we wish, in some cases they
9 might be.

10 MR. RADLINSKI: Mr. Jarmer, just a comment.
11 I trust that you have commented on the draft OCS orders
12 that have been published in the Federal Register and I
13 might add that we'd be pleased to sit down and talk with
14 the Board about these orders if they're developed in final
15 form.

16 MR. JARMER: Fine. Thank you.

17 JUDGE MOORE: Thank you, sir.

18 I now call Mr. Zedrosser.

19 If you have copies for the panel, that
20 would be appreciated. If you don't, please give one to the
21 reporter.

22 MR. ZEDROSSER: My name is Joseph J.
23 Zedrosser. I am an Assistant Attorney General in the
24 office of Louis J. Lefkowitz, Attorney General of the
25 State of New York. I will present a brief overview of
the position of the Attorney General today and will submit

**NERBC-RALI
Project**

**Onshore Facilities Related to
Offshore Oil and Gas Development**

2824

A report of the New England River Basins Commission (NERBC) project 'Development and Application of a Methodology for Siting Onshore Facilities Associated with OCS Development' conducted under agreement with the Resource and Land Investigations (RALI) Program of the U.S. Department of the Interior, Geological Survey.

Factbook

November, 1976

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TRANSPORTATION FACILITIES

This chapter discusses the two major alternatives for transporting oil and gas from offshore production facilities to onshore facilities: marine pipelines, and tankers or barges, and the strategic factors that influence which alternative is chosen. A marine pipeline system consists of a pressure source, gathering lines, a pipeline, intermediate pressure boosting facilities (if necessary), and a landfall site. A tanker or barge transportation system consists of offshore storage and loading facilities, tankers or barges, and a marine terminal. In some cases, mixed systems are used. Oil may be piped from the offshore platform to a marine terminal for transshipment to oil refineries in other regions by tankers or barges. A marine terminal facility consists of berths for tankers or barges, crude oil loading and unloading equipment, storage tanks, ballast water treatment facilities, and other harbor facilities.

In general, pipelines are the preferred method of transporting oil to shore. Because of the very high costs of constructing marine pipelines, companies constructing pipelines will tend to minimize the length of the marine pipeline by selecting the shortest possible route.



TRANSPORTATION FACILITIES
SUMMARY OF REQUIREMENTS AND IMPACTS

PIPELINES AND LANDFALLS

Land:	50-100 foot right-of-way for landfall 40 acres for pumping station if required at landfall 60 acres for tanker and barge terminal if required at landfall
Installation Labor and Wages:	250-300 jobs for each lay barge spread (20 percent local employment) (very little employment during pipeline operation) average unskilled wage: \$15,000/year average skilled wage: \$25,000/year total per lay barge spread: approx. \$5.5 million
Air Emissions	minimal; chiefly hydrocarbons from valve and pump seal leaks and sulfur oxides, hydrocarbons and nitrogen oxides from compressors along the route
Noise:	90-100 dB (uncontrolled level) from compressors 140 dB from once-a-year venting at pipeline

TRANSPORTATION FACILITIES
SUMMARY OF REQUIREMENTS AND IMPACTS continued

MARINE TERMINALS

	<u>Pipeline Tanker and Large Terminal</u>	<u>250 MBD Shoreside Terminal/ Tank Farm</u>	<u>250 MBD Mid-Depth Terminal/ Tank Farm</u>
Land	60 acres	15-20 acres	35-40 acres
Draft Requirements	30-35 feet	30-35 feet	50-60 feet
Labor	25	65	37-65
Total Annual Wages	\$ 400,000	\$ 1,100,000	\$ 1,100,000
Capital Investment	\$9,800,000	\$20,000,000	\$27,500,000
Air Emissions -	• Hydrocarbon emissions from storage tanks and transfer operations • exhaust emissions from boaters, sumps and compressors		
Water Emissions -	• Bilge Water,) BOD, COD, total sus- • Ballast Water) -pended solids, Oil and • Storm Runoff) Grease • chronic small oil spills from handling operations • infrequent major oil spills from groundings, collisions and other accidents.		

TRANSPORTATION STRATEGY

Several factors influence the decision whether pipelines or tankers and terminals are used. These include the size of the find, the distance from shore, meteorological conditions, oceanographic conditions, whether the find is gas or oil, the ultimate destination of the produced crude, and the availability of terminals.

Size of Find

Because they are very expensive to construct, pipelines must be able to handle large volumes of oil or gas to justify their construction. A pipeline will not be constructed until the company developing a field is certain that it has found a commercially valuable reserve of recoverable crude oil or natural gas. Barges and tankers may be used to transport crude from small oil finds until such time as additional finds are made in the area which could justify pipeline construction.

Distance from Shore

If a well is located close to shore, it is more likely that a pipeline will be used than tankers (all other factors remaining constant). Tanker terminal operation costs per mile tend to fall as distance increases because the costs of berthing and unloading operations are high, relative to the costs of tanker movement. However, long distances do not necessarily imply that tankers will be used.

Meteorological Conditions

Since offshore tanker/barge loading operations can not take place during strong winds and high waves, the tanker/terminal transportation alternative is not attractive in areas frequently exposed to adverse weather conditions. Weather delays result in production shut downs and interruption of the supply of crude oil. In such conditions it may be more economical, in the long run, to construct a pipeline.

3.5

*Transportation Strategy (continued)*Oceanographic
Conditions

Pipeline feasibility can be influenced by a number of oceanographic conditions, including depth of water, bottom currents, bottom slope, relief and topographic conditions, sub-sea obstacles, rock outcroppings and other bottom conditions. Some conditions, such as extreme depths, make pipelines technologically infeasible, while other conditions, such as slope, currents, and bottom characteristics, may require engineering solutions and alternatives that are simply too expensive for the project to be economically feasible.

If the Find is Gas

If natural gas is found in commercial quantities, it is far more likely that it will be brought ashore by pipeline than by tanker. Shipping gas requires the construction of offshore liquification facilities and the use of special tankers to transport the liquified natural gas. Because of the expense of offshore liquification, natural gas is almost always brought ashore by pipeline.

Destination
of the Crude

The ultimate destination of the crude is, of course, the refinery, and both the location and ownership of the refinery can affect the transportation decision. If oil is produced in a frontier OCS area, there are several alternatives for transporting it to refineries, based on the location of the refinery. If the oil is to be refined in the region adjacent to the oil field, it will either be piped to shore, or tankered or barged from offshore loading facilities at the platform to a land-based marine terminal. Oil would then be piped from the landfall or terminal to the refinery by an over-land pipeline.

If the oil is to be refined in another region, two options exist: the oil may be loaded offshore onto tankers or barges and transported directly to the marine terminal serving that refinery; or the oil may be piped to shore in the region adjacent to the oil field and then transshipped to the refinery.

In some cases oil companies may "swap" crude. If two oil companies are producing oil in separate regions

and each company's refinery is located closer to the other company's find, they may simply exchange crude to save the extra expense of shipping the crude to their own refineries.

Availability of
Existing
Terminals

The availability of existing terminals will affect transportation strategies for subsequent development. If a producer has access to a marine terminal capable of receiving or transshipping offshore crude, it is more likely that he will use it, particularly for small and distant finds, than build a pipeline.

The U.S. Experience

Most of the oil and all the gas produced on the U.S. Outer Continental Shelf is transported by pipeline. Pipelines are safer and generally more economical than tankers, barges, and marine terminals and provide continuous transportation of crude oil and gas, independent of weather conditions which cause costly production shut downs and supply interruptions. In the U.S., approximately 98 percent of all offshore oil produced is brought to shore via pipeline.

The North
Sea Experience

Offshore storage and loading facilities have been used to a greater extent in the North Sea than in U.S. OCS areas. In the Norwegian sector of the North Sea, the Phillips Petroleum Company has constructed a one million barrel capacity offshore storage facility at their Ekofisk Field. A pipeline from the field to Norway was considered uneconomical because of the seabed conditions and the deep trench located between the field and the shore.

Several marine terminals have also been constructed in the North Sea. In the Orkney Islands in Scotland, a marine terminal combined with processing and storage facilities was constructed to accommodate production from the Piper Field, located 130 miles east of the islands. Crude oil and some associated gas is delivered to the terminal by a 30 inch diameter marine pipeline, processed, and shipped out in tankers normally ranging in size from 60 to 100 thousand dead weight tons (DWT).

Transportation Strategy (continued)

An analysis of the transportation system for an oil field located 90 miles east of the Shetland Islands indicated that for a daily production rate greater than 150,00 barrels per day, a system which included a 90 mile pipeline to shore, a marine terminal in the Shetland Islands, and transshipment by tankers to a refinery in mainland Scotland (a distance of 185 miles), was preferable to offshore loading and direct shipment to Scotland by tankers (a distance of 205 miles).

Once the location of the find and ultimate destination of the crude were determined, the analysis was particularly sensitive to three variables: the production rate of the field, the size of the tankers used at the terminal and for offshore loading, and the amount of tanker downtime which would result from adverse weather conditions.

Unit transportation costs were higher for the pipeline transshipment for low production rates but decreased faster than direct shipment as production rates increased. The point at which the pipeline - transshipment alternative became more attractive than the direct shipment alternative was at a daily production rate of 150,000 barrels per day.

A marine terminal could accommodate tankers twice the size of those that could operate at the offshore loading facilities. The use of larger tankers significantly reduced operating costs.

Because of the costs associated with tanker downtime resulting from adverse weather conditions, the analysis was sensitive to estimates of downtime. As downtime increased, the pipeline and terminal alternative became more attractive.

In general, large volumes of oil and/or gas at relatively short distances from shore will justify the construction of pipelines where they are technologically feasible. Scattered commercial size finds at long distances

A marine pipeline system is one of the methods for transporting oil and gas from offshore production to onshore processing facilities. A pipeline is safer and more dependable than a tanker or barge system and is generally more economical for large volumes of gas and oil.

Marine pipelines are installed by a combination of work vessels consisting of a lay barge, one to three tug boats, several pipe supply boats or barges, and bury (jet) barges (where pipelines are to be buried). These are referred to as a "work spread" or a "lay barge spread" by the pipelaying industry. Figure 3.1 shows a lay barge in operation along with a tug boat.

DESCRIPTION OF FACILITY

Components of the System

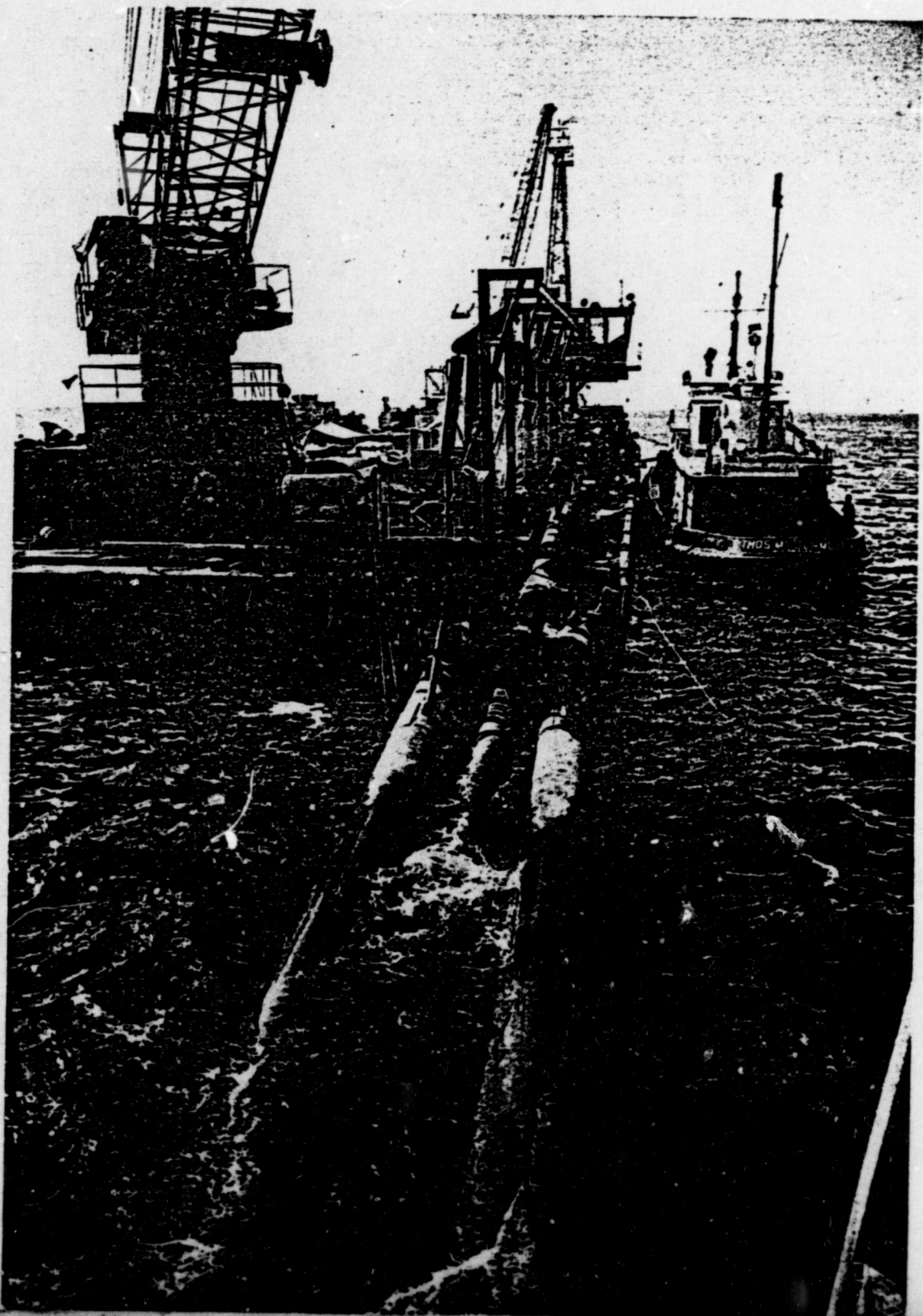
A marine pipeline system may include a number of components: a pressure source, gathering lines, pipelines, intermediate pressure booster stations (if necessary) a landfall, and an onshore destination.

Pressure Source. The pipeline may originate from a single production platform or from a number of platforms connected by a network of smaller diameter pipelines. In some cases, the formation pressure may be sufficient to drive the oil or gas to shore. However, pumps are usually required for oil pipelines and compressors are often used for gas pipelines. Pumps and compressors, located on offshore platforms, are provided with safeguards against overpressuring the pipelines.

Gathering Pipelines. Oil and gas from several platforms or fields is normally brought together by a system of small diameter gathering pipelines and transported to shore in a single large pipeline. The use of gathering pipelines allows for greater utilization of the

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FIGURE 3.1
PIPELINE LAYING OPERATION



Timing, Trends, and Options (continued)

sea bed photography, and the use of current meters. For a 110-mile oil pipeline from the Forties Field in the North Sea to Scotland, survey work was spread out over three years and cost in excess of \$500,000.¹²

Landfalls

The general location of a landfall site is primarily determined by the shortest possible route between the production platform and land. Once the general location for landing a pipeline has been selected, the choice of landfall site will depend upon the physical characteristics of the shore and the company's production plans.

A company bringing a gas pipeline ashore will seek a landfall site within a reasonable distance of a parcel of land large enough to construct gas processing facilities. These facilities need not be constructed at the landfall site, but suitable land should be available between the landfall and the nearest gas transmission line. (Refer to Chapter on Gas Processing Plants for characteristics and requirements of gas plants.)

If oil and gas were being brought to shore in the same pipeline, it would be desirable from the company's viewpoint to have a site for partial processing facilities as close to the landfall site as possible because of the high costs of transporting oil and gas in the same pipeline. (Refer to Chapter on Partial Processing for characteristics and requirements for partial processing facilities.)

For an oil producing company wishing to transport oil from the landfall by tanker, the main physical criteria for choosing a landfall will be the availability of a suitable tanker terminal site and sufficient land nearby for a tank farm. The company will also look for an easy landfall for the pipe, with requirements very similar to those of a gas pipeline landfall.

If the company plans to transport crude oil further inland to a refinery by pipeline, then the shortest distance between the oil field and the ultimate destination for the crude oil may assume greater importance in the selection of a landfall site. However, the shortest possible distance between the field and land would be given more weight than the direct distance from the field to the ultimate destination because marine pipeline costs are much higher than onshore pipeline costs (by a factor of two or more in some cases).

¹² D.B.L. Walker, p. 821.

CHARACTERISTICS
REQUIREMENTS
AND IMPACTS

Pipeline Siting
Criteria

The single most important siting criterion for marine pipelines is that they should follow the shortest possible route from platform to land because of their very high cost. However, great depths and steep slopes can also modify the route. Furthermore, the pipeline route will avoid anchorage areas, existing underwater objects, active faults, rock out-crops, mud slide areas, and areas which are environmentally sensitive or likely to generate public opposition.

The shore approach should be gently sloping with sufficient depth of sand or shingle to give not less than 10 feet of cover over the pipeline down to the low water mark and 7 feet of cover out to a depth of 50 feet. Areas subject to seabed shifting or strong tidal flows should be avoided. Erosion caused by such action could undermine pipeline support, placing additional stress on the pipeline and possibly causing it to fail.

The landfall site should allow for a flat approach or reasonably gentle transition from marine to land environment. However, cliffs up to 100 feet can be accommodated if the rock is soft. The landfall site should also be in a non-urban area.

The experience of Shell U.K. Exploration and Production Limited with their gas pipeline from their Leman Field in the North Sea to their gas terminal in Bacton, Norfolk County, England shows some of the trade-offs involved in pipeline route selection. The shortest route between the production platform and the shore involved a crossing of the Haisborough Sand Bank which is 11 miles long, 1 mile wide, rises some 80 feet above the sea bed with steep slopes, and is the resting place for a number of charted wrecks. Preliminary surveys indicated the possibility of a passage for pipe laying vessels through the barrier. The final route investigations concentrated on the direct route across the Haisborough Sands and a less direct route to the North of the Sands.

According to the testimony given before the Norfolk County Council by an official of Shell U.K. Exploration and Production Limited, the only acceptable route was the less direct route avoiding the Bank. The reasons for the decision included: (1) Detailed depth soundings indicated that, because the Sands had moved considerably in the recent past, a pipeline through the area would likely be subject to exposure and might become endangered and an interference to fishing at a later date. (2) Tide and swell conditions at the Sands especially at low water, were particularly severe and would have made exact positioning of any pipe laying vessel extremely difficult. (3) Even though a passage, navigable only at high tide, was found through the Sands, it was too marginal from the point of view of depth, safety, and working conditions. (4) The survey indicated a sizable uncharted wreck partially across the only passage found through the Sands. (5) The route to the coast and to the platform from the Sands had an irregular bottom surface and hard beds which would have impeded pipeline burial. ¹³

Land Requirements

Pipelines do not require very much land. Once they come ashore, they normally require a minimum right of way of between 50 to 100 feet. The pipeline companies will purchase some of this land in fee and purchase easements for the rest to allow them to use the land during construction and maintenance activities.

If an oil pipeline comes ashore and transports the oil any appreciable distance further inland, pumping stations are normally required near the landfall site. The station could require 40 acres of land and consists of storage tanks, an office, and a pump station.

¹³ Testimony of Kenneth Henry Davison, Shell U.K. Exploration and Production Limited, before the Norfolk County Council, Smallburgh Rural District Council, England, 1967.

Characteristics, Requirements, and Impacts (continued)

Oil might be piped to a pipeline tanker and barge terminal facility. The facility would require a waterfront location of about 60 acres and a 35 foot minimum water depth. Ample storage would also be needed to service shuttle barges and tankers.

Gas pipeline landfalls have roughly the same right-of-way requirements as oil pipelines. Processing facilities would be located along the right-of-way between the landfall site and the closest gas transmission line. The landfall site itself may be nothing more than a strip of land 100 feet wide. The size of the landfall depends on the physical characteristics of the site and the type of equipment that is necessary to complete construction.

Labor
Requirements

Pipelines generate a significant amount of employment during the construction phase but very little during operation. The amount of employment depends on the number of lay barge spreads operating at a given time, as well as the number of pipelines being constructed.

A lay barge spread consists of a lay barge, one to three tug boats, and pipe supply vessels (or cargo barges). In addition, bury barges and diving barges are often used during construction activity. A lay barge will employ about 200 people on the average while bury barges employ about 35 people and tug boats about 5 or 6. An average of 5 cargo barges are assigned to each lay barge and there is usually 1 tug assigned for every 2 cargo barges. Local employment opportunities might be as low as 20 percent.

The average annual wage rate for pipelaying activities may be \$21,500, with skilled labor averaging \$25,000 per year and unskilled labor averaging \$15,000 per year.

An onshore pumping station (also referred to as a pipeline shore terminal) would employ approximately 17 people. Table 3.1 shows employment and wages for a pumping station/pipeline shore terminal with a 200,000 barrel per day capacity.

*Characteristics, Requirements, and Impacts (continued)*Oil Spills

Spills of petroleum onto land or into fresh or salt water resulting from breaks in the pipeline are potentially the most important environmental impact.

Causes of Oil Spills. There are many different causes of petroleum pipeline spills, including external corrosion, damage from equipment such as anchors and fishing nets, defective pipe seams, internal corrosion, and improper operation by personnel. Table 3.3 shows a summary of liquid petroleum pipeline system accidents which released 50 barrels or more of product during the year 1972. (Figures are from the Office of Pipeline Safety, U.S. Department of Transportation.) A total of 309 accidents were reported based on approximately 175,000 miles of trunk lines (both onshore and offshore pipelines).

TABLE 3.3
LIQUID PIPELINE ACCIDENT SURVEY
January 1, 1972 - December 31, 1972

<u>Cause</u>	<u>Number</u>	<u>% of Total</u>	<u>Size of Spill (bbls)</u>
external corrosion	75	24.4	40,475
equipment rupturing line	69	22.3	83,592
defective pipe seam	28	9.1	43,303
internal corrosion	25	8.1	38,988
improper operation	22	7.1	45,885
miscellaneous	13	4.2	13,070
other (18 other causes)	77	24.8	95,341
	309	100	360,654

Source: U.S. Department of Transportation,
Office of Pipeline Safety, 1973.

The safety record for pipelines installed since 1960 indicates some of the technological progress that has been made by the industry. Of the 75 failures resulting from external corrosion, only one of them involved a

pipeline installed after 1960.¹⁹ This can be partly attributed to the fact that the older a pipe is the more likely it is to corrode externally, but is also due to pipe coating and pipe quality control measures that have been instituted since 1960.

A major cause of damage to marine pipelines is damage from external equipment such as anchors and fishing equipment. The largest spill in the Gulf Coast occurred in 1967 when a pipeline failed as a result of anchor damage sustained two years earlier. The leak was not discovered for 10 days, by which time 167,000 barrels had been discharged.²⁰ Pipeline operations are monitored much more closely today, with pressure monitoring valves on each end of the pipeline which are capable of shutting down the line, if necessary, and by periodic inspection of the waters around the pipeline route.

Oil Spill Cleanup. There are several options for dealing with oil spills, including leaving it, burning it, sinking it, containing and removing it, and dispersing it.

Small spills which occur in rough seas under adverse conditions may pose little threat to shoreline or marine life. These might be left to be eliminated by natural turbulent dispersion and biodegradation processes.

¹⁹ D. E. Broussard, p. 5.

²⁰ Don E. Kash, p. 68.

Characteristics, Requirements, and Impacts (continued)

Oil can be burned on the surface of the sea, but complete destruction of an oil slick by this means is not usually possible. Burning, even when burning agents are used, is usually incomplete and causes significant air pollution.

Oil can be made to sink to the bottom by the addition of special sinking agents. However, the sunken material is not stable and is subject to both vertical and horizontal movement, due to current and wave action, and will produce long term impacts on bottom organisms. "Sinking agents may be used only in marine waters exceeding 100 meters (328 feet) in depth where currents are not predominantly on-shore, and only if other control methods are judged by EPA to be inadequate or not feasible."²¹

Skimming and absorbing the oil and its subsequent removal are the usual methods of mechanical treatment. Skimming devices take three principal forms: suction, weir or surface type skimmers. A suction skimmer floats on the sea and has openings near the water line. Suction pumps draw the oil-water mixture through these openings and the mixture is then pumped to a recovery tank. To work effectively, the motion of the skimmer must follow that of the sea surface closely. A weir skimmer is designed so that oil will flow over the 'weir', a vertical dam with its top slightly below the water surface, then the oil is pumped into a container. The surface-type skimmer consists of a moving disc, or belt, which is moved through the oil. The oil adheres to the moving surface, from which it is scraped off into a collector, prior to the moving surface re-entering the oil slick. To

²¹ U. S. Environmental Protection Agency, Control of Oil and Other Hazardous Materials, June 1974, p. 27-4.

Characteristics, Requirements, and Impacts (continued)

be effective, all these skimmers require that the film thickness of the oil slick be increased by means of a floating barrier. In the past, their use has been confined to sheltered waters since they could not operate efficiently when wave height or periodicity exceeded certain limits. However, the latest designs are claimed to operate in 2 metre (6 feet) waves. When contained by a suitable barrier, they are claimed to have a recovery rate of over 100 tons per hour.

Absorption methods involve the use of material which absorbs the oil, for example, straw, peat or polyurethane foam chips. The main disadvantage is that it is a triple operation, requiring first the distribution of the absorbent over the oil and, subsequently, its removal and disposal. Disposal of large quantities of contaminated absorbent can create additional environmental problems. The polyurethane chips have the advantage of both greater absorption properties and the possibility of re-use after the contaminated oil has been wrung out. Due to the slow rate of recovery obtained using this method, its use has been restricted to small slicks. However, its effectiveness is increased by wave action and, thus, it can be used in adverse sea conditions.²²

An oil spill can be broken up by the use of chemical dispersants, such as detergent. They are effective in breaking up oil spills and are not limited by adverse weather conditions. However, the major problem with the use of dispersants is that the chemical dispersants, themselves, when mixed with oil, have toxic affects on marine biota. The use of dispersants is the favored approach in the United Kingdom. In the United States, however, there has been a reluctance to use the method because of the remaining uncertainties about potential toxic effects.

Under the terms of the Water Quality Improvement Act of 1970 (PL 91-244) dispersants shall not be used:

²² W.J. Cairns Assoc., Flotta Orkney Oil Handling Terminal, Report 3, Marine Environment Protection, prepared for Occidental of Britain, Inc., 1975, p.37.

Characteristics, Requirements, and Impacts (continued)

1. on any distillate fuel
2. on any spill of oil less than 200 barrels
3. on any shoreline
4. in waters less than 100' deep
5. in any waters containing major populations or breeding or passage areas for species of fish or marine life which may be damaged or rendered commercially less marketable by exposure to dispersant or dispersed oil.
6. in any waters where winds and/or currents are of such velocity and direction that dispersed oil mixtures would likely, in the judgement of EPA, be carried to shore areas within 24 hours.
7. in any waters where such use may affect surface water supplies.²³

Air Emissions

Pipelines and landfalls contribute few airborne pollutants in relation to other operations involved in OCS development. During the operational phase, air emissions will be generated primarily from two sources, compressors and pumping stations along the route and leakage from valves and seals along the route.

Compressors are used to maintain proper operation pressures along a gas pipeline. They are fueled by either natural gas or refinery gas and their major emissions are sulfur oxides (SO_x) and hydrocarbons (Table 3.4).

TABLE 3.4
EMISSIONS FROM COMPRESSORS FUELED
BY NATURAL GAS

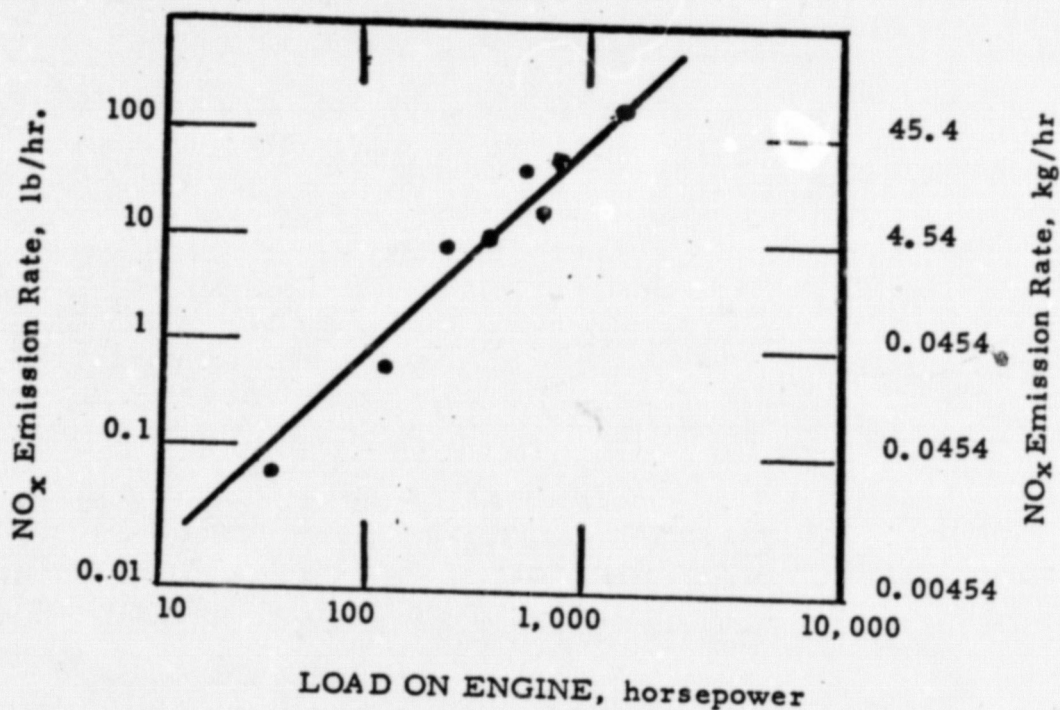
<u>Pollutant</u>	<u>lbs/million cu. ft.</u>	<u>lbs/hr</u>
Sulfur Oxides	.6	-----
Hydrocarbons	1.2	4.2

Source: EPA, Compilation of Air Pollutant Emission Factors, 2nd edition, 1976, p. 3.3. 2-1.

²³ Ibid. p. 27-3.

Nitrogen oxide emissions of gas compressors are a direct function of the load on the compressor engine. This relationship is presented in figure 3.9.

FIGURE 3.9
NITROGEN OXIDE EMISSIONS FROM COMPRESSOR
ENGINES



Source: EPA, Compilation of Air Pollutant Emission Factors, 2nd edition, 1976, p. 2.3.2-2.

Hydrocarbon leaks occur at numerous locations along pipelines -- at pump seals, compressor seals, relief valves and pipeline valves. A study of air emissions for a report on a Southern California OCS lease sale concluded that the major source of leakage was pump seals.²⁴

²⁴ State of California Air Resources Board, "Summary of Emissions of Southern California OCS and Santa Barbara Channel OCS Development." December 1975, unnumbered.

The overall impact of normal pipeline operations on ambient air quality appears to be minimal.

If a leak of natural gas occurs as a result of pipeline rupture or break, the highly flammable and asphyxiating natural gas would be a health and safety hazard.

Chronic Petroleum Leakage

Chronic low level leakages of petroleum become dissolved in the water surrounding the marine pipeline as a result of normal pipeline operation. The volume emitted is a function of the design of the pipeline (type of joints, etc.) and the number of fittings and valves.

Little information is available on the extent of impacts generated by low but continuous concentrations of hydrocarbons in the marine environment. Site-specific physical characteristics such as mixing rates and retention times and the susceptibility of local organisms to both lethal and sublethal effects of continuous low hydrocarbon concentrations will determine the severity of impact.

Noise

Increased ambient noise levels can be expected in the area of a pipeline corridor, particularly in the vicinity of a booster station where compressors will be located. Compressors generate approximately 92 to 100 dB (A) of noise while operating, which exceeds current federal standards.²⁵ This uncontrolled level is audible in a 6,000 - 7,000 foot radius from the site on a 24-hour basis.²⁶ Silencers built into the compressors can lower the noise level to

²⁵ U. S., E P A. . Noise from Industrial Plants, prepared by L. S. Goodfriend, (1971), p. 12.

²⁶ Federal Power Commission, Final/Environmental Impact Statement for the Alaska Natural Gas Transportation Systems, Vol. II, (April 1976), p. 316.

Characteristics, Requirements, and Impacts (continued)

between 56 and 61 dB (A) 800 feet from the boundary of the station.²⁷ Approximately once a year, venting of high pressure gas in a pipeline and at the compression station occurs. Venting lasts approximately 45 minutes on the pipeline and five minutes at the compressor site. Uncontrolled noise levels peak at about 140 db(A) 100 feet from the stack and are audible up to 15 miles away. Stack silencers are available which lower this level to 80 db(A).²⁸

Solid Wastes

There are no significant solid wastes associated with normal operation of pipelines. When pipeline spills occur, however, the oil that is spilled is collected and recovered to the extent possible and discarded when it is not practical to recover oil. All such waste must be disposed of at a landfill site suitable for hazardous wastes. Special care must be taken in disposing of the crude oil wastes so that the hydrocarbons contained in the crude oil are not released to the atmosphere or to surface or ground waters. The amount of petroleum spilled and its frequency can not be easily predicted.

Aesthetics

The aesthetic impacts of pipelines depend on the site restoration practices employed at the time of construction. When proper care is taken, pipelines may not be noticeable. In other cases, the trenches through wetlands, and other types of habitats where vegetation is not easily restored, could have significant aesthetic impacts. Aesthetic impacts of pipelines may be less important than those of the facilities that may be associated with them onshore such as gas plants, partial processing facilities, marine terminals, and storage tanks.

²⁷ Ibid. p. 216-C.

²⁸ U. S. Department of Interior, Draft Environmental Impact Statement-Alaska Natural Gas Transportation System, Part I Overview, Vol. I, (June 1975), p.403.

PARTIAL PROCESSING FACILITIES

SUMMARY OF REQUIREMENTS AND IMPACTS

Land:	15 acres per 100,000 barrels of oil and associated gas to be processed
Water:	10,000 gallons per month
Energy:	1.5 million SCFD/month gas 400,000 kwh/month
Labor:	150 construction field jobs (oil and gas facilities); approximately ten jobs during operation
Wages:	\$14,400/year (operation)
Capital Investment:	\$13 million (110,000 BPD capacity)
Construction Period:	15 months
Air Emissions:	Hydrocarbons, hydrogen sulfide, sulfur oxides, nitrogen oxides
Major Wastewater Contaminants:	Suspended solids, oil and grease, heavy metals, phenols, halogens, chromium
Noise:	80-90 decibels from pumps; 81-96 decibels from flare stacks; 81-96 decibels from treating vessels.



PARTIAL PROCESSING FACILITIES

DESCRIPTION OF FACILITY

Partial processing facilities are designed to remove impurities from a crude oil well stream. A crude oil well stream consists of crude oil, natural gas, and formation water. Formation water consists of brine water (which can be in the form of an oil-water emulsion), dissolved solids and suspended solids. Generally, natural gas is removed from the well stream at the platform and handled separately.

The liquid components of the well stream are partially processed to remove free and emulsified water, dissolved solids, and suspended solids from the crude oil. Partial processing generally reduces water and sediment content of the oil well stream to approximately one percent. Once the crude oil is partially processed, it is delivered to a refinery where it is converted to a wide range of petroleum products. (See Chapter 6, "Refineries".)

Partial processing facilities are designed for the specific characteristics of the well stream and in conjunction with the rest of the development strategy. They may be located as separate facilities or they may be collocated with marine terminals and/or gas processing facilities.

Figure 4.1 shows the Phillips Petroleum Company's LaConchita processing facility. The plant, located in Ventura County, California, is designed to process 30,000 barrels of oil per day (BOPD), 15,000 barrels of water per day (BWPD), 30 million cubic feet of gas per day (MMCFGD), and actually processes, on the average, 5,000 BOPD, 10,000 BWPD, and 20 MMCFGD.

The plant is served by a single pipeline which delivers crude oil from two production platforms located six miles offshore and in 170 feet of water. The plant occupies an 11-acre site, of which 75 percent is intensively developed with buildings, equipment, and ancillary facilities. The plant

4.3
Description of Facility (continued)

FIGURE 4.1
PHILLIPS PETROLEUM COMPANY'S LACONCHITA
PARTIAL PROCESSING PLANT,
VENTURA COUNTY, CALF.

4.4 Description of Facility (continued)

took about two years to construct, cost approximately \$3.5 million, and went into operation in 1968. It employs up to a total of nine people over three shifts.¹

Figure 4.2 shows Mobil Oil Company's Rincon onshore processing facility. The plant, located in Seacliff, California, has an existing capacity of 110,000 barrels of gross fluids (oil and water) per day and averages 32,700 BOPD, 9,800 BWPD, and 11.8 MMCFGD.² The plant is served by a single crude oil pipeline, which originates at a production platform located six miles offshore in the Santa Barbara Channel in 200 feet of water. The plant occupies a 120-acre site, of which 14 acres are used for processing and 17 acres are used for ancillary purposes. The plant was built in 1969 at a capital cost of \$13 million. It employs seven people over three shifts.³

Figure 4.3 shows the layout for a partial processing facility constructed as part of a marine terminal in the Orkney Islands of Scotland. The Flotta Terminal is designed to handle 250,000 barrels of oil per day (BOPD), 15,000 barrels of produced water per day (BWPD), and 6,000 barrels of petroleum gas liquids per day. The terminal occupies a site of 340 acres, of which less than 100 acres are used intensively. The oil processing facilities (exclusive of crude oil storage) occupy approximately four acres. The terminal is served by a 30-inch diameter crude oil pipeline which originates at Piper Field, 130 miles offshore in the North Sea. The crude oil passes through separators and electrostatic de-

¹ Communication with Phillips Petroleum Company, Santa Barbara, California, October 10, 1976.

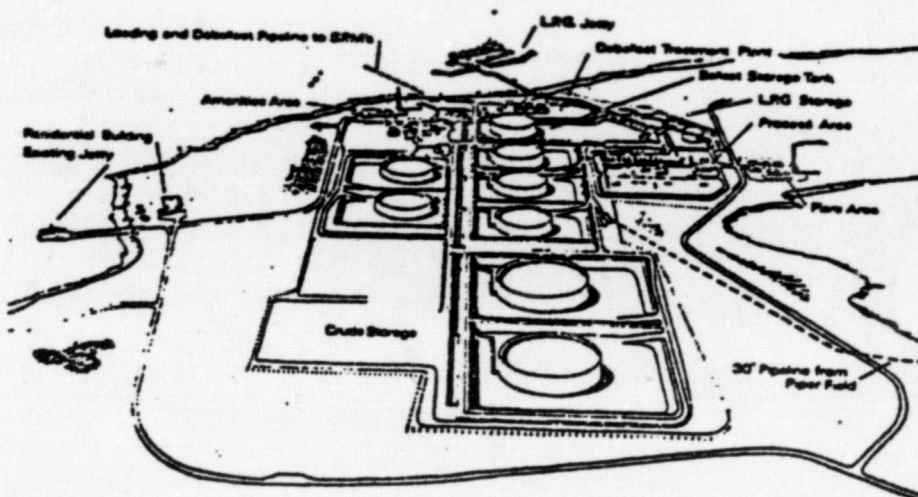
² The well stream received by the Mobil plant has the free water removed on the platform, while offshore free water removal does not take place for the well stream received by the Phillips facility, accounting for most of the wide range in water content between the two plants.

³ Communication with Mobil Oil Corporation, Los Angeles, California, October 8, 1976

4.5
Description of Facility (continued)

FIGURE 4.2
MOBIL OIL COMPANY'S
RINCON PARTIAL PROCESSING PLANT,
SEACLIFF, CALF.

Figure 4.3
PARTIAL PROCESSING FACILITY AT MARINE TERMINAL
IN ORKNEY ISLANDS, SCOTLAND



Source: Robert W. Trainor, J.R. Scott, and W.J. Cairns, "Design and Construction of a Marine Terminal for North Sea Oil in Orkney, Scotland", Proceedings of the Eighth Annual Offshore Technology Conference, (Houston, Texas, 1976), p. 1078.

4.7 *Description of Facility (continued)*

salters that separate the crude from the water and breaks up the oil-water emulsion. Natural gas is processed to remove the liquifiable hydrocarbons, while the remaining gas is used to fuel the facility's equipment.⁴

Figure 4.4 shows the layout for a proposed partial processing plant that is to be collocated with gas processing and treatment facilities. The proposed Las Flores processing facility, located in California adjacent to the Santa Barbara Channel, would occupy a site of approximately 15 acres and would have facilities for oil treatment, oil storage, gas processing and treatment, and liquefied petroleum gas storage, as well as ancillary facilities. The plant would be fed by a 16-inch crude oil pipeline and a 12-inch gas pipeline, both of which would originate 6.7 miles offshore in the Santa Ynez unit in the Santa Barbara Channel. The facility would be designed to initially process 40,000 BOPD, 10,000 BWPD, and 20 million cubic feet of gas per day (MMCFGD) with potential to expand to 80,000 BOPD, 20,000 BWPD, and 90 MMCFGD. Crude oil would be piped to a nearby marine terminal, natural gas would be piped to an existing commercial gas transmission line, and natural gas liquids would be delivered by pressurized tank trucks to markets in neighboring areas.⁵

Gas Separation

When natural gas is produced in association with crude oil, it must be separated from the rest of the well stream. This generally takes place on production platforms.

The natural gas, which is suspended in the crude oil under pressure, is released as the well stream passes through a series of separation vessels, each vessel operat-

⁴ Robert W. Trainer, J.R. Scott, and W.J. Cairns, "Design and Construction of a Marine Terminal for North Sea Oil in Orkney, Scotland," Proceedings of the Offshore Technology Conference, Houston, Texas, May 3-6, 1976, Vol. III, pp. 1067-1073.

⁵ U.S.G.S., Final Environmental Statement Proposed Plan of Development Santa Ynez Unit Santa Barbara Channel, Off California, 1974, Vol. I.

ing at successively lower pressures. In some cases, a single separator may be sufficient for removal of natural gas, while in cases where formation pressures are high, a series of three separators may be used.

Two different types of separators may be used on platforms: two-phase separators and three-phase separators. Two-phase separators merely separate the natural gas from the rest of the well stream. Three phase separators split the well stream into three components: natural gas, crude oil (including some emulsified water), and free water. The gas, oil, and water separate by gravity under pressure within the vessel, and are drawn off by valves located at the phase interfaces.

Once the gas has been separated from the rest of the well stream, the well stream is partially processed.

Oil-Water Separation

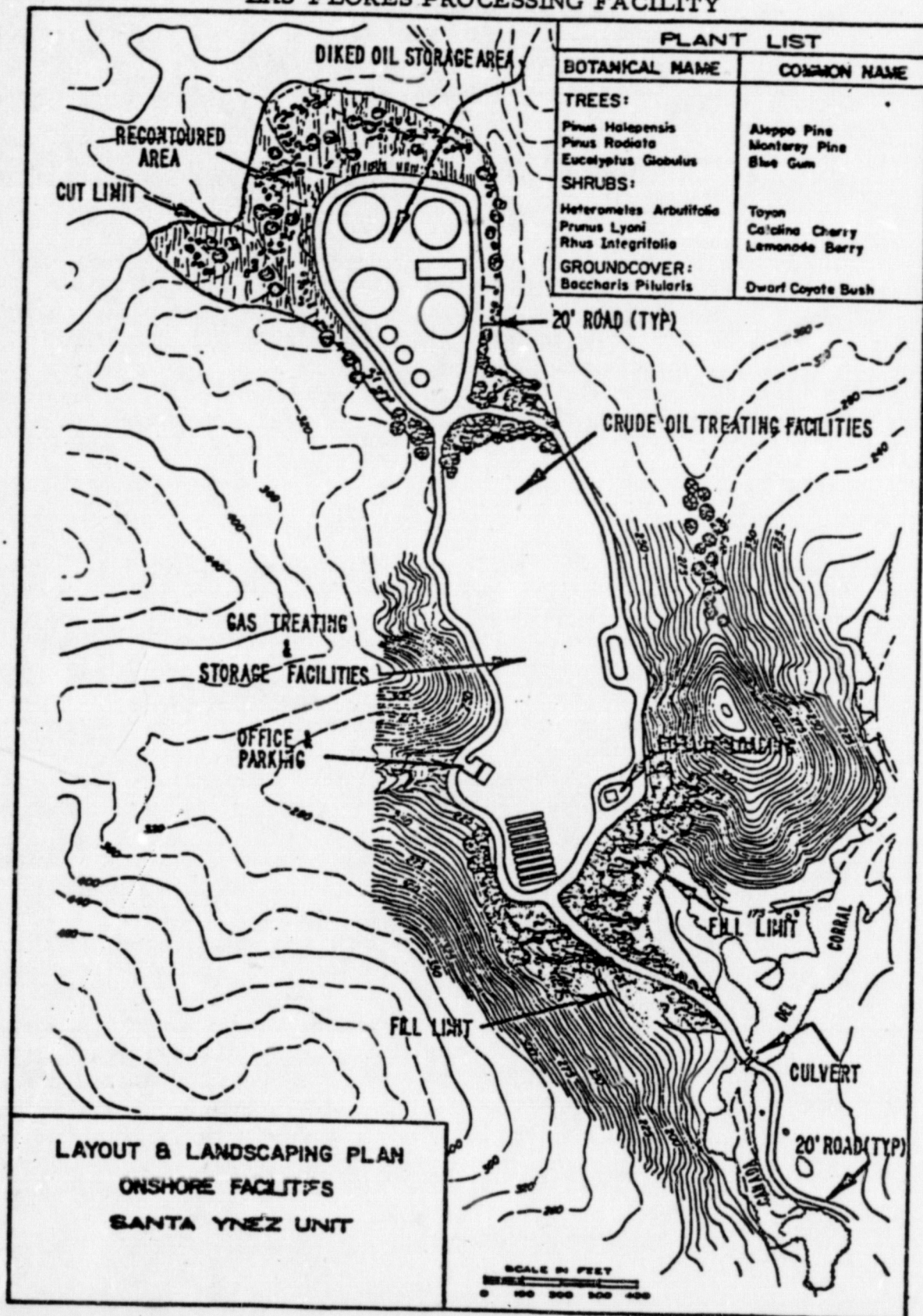
Oil and water separation involves the removal of free water and emulsified water from the crude oil well stream. In some cases, water removal is accomplished in two steps. Free water may be removed on the offshore platform, either in a three-phase separator or in a vessel called a free water knockout drum. The water is treated before it is discharged, while the oil (which normally contains some water in the form of an oil-water emulsion) is piped to shore for further water separation. In other cases, the entire liquid well stream is piped to shore for processing, while in rare cases, all water is separated in one step on offshore separation facilities.

Equipment used for the separation of free water from crude oil is relatively simple and is generally located on offshore production platforms. Phase separators and free water knockout drums separate oil and water under pressure by gravity.

Equipment used for the separation of emulsified water from crude oil is relatively complex and is generally located onshore. Several methods are used to separate the emulsified water from the crude oil, including the application of heat, electrostatic, and chemical action. If emulsion treaters

FIGURE 4.4

LAS FLORES PROCESSING FACILITY



Source: U.S.G.S., Final EIS Santa Ynez Unit, 1974, p.I-40.

and heater treaters are constructed offshore, they are usually placed on separate processing platforms, or barges, because they would constitute a safety hazard on a production platform.

The water which is separated from the crude oil will contain considerable amounts of oil which must be removed before the water can be discharged.

Water
Treatment

Water treatment equipment is designed to remove oil from water to such a degree that the water is suitable for discharge. Normally, the effluent from water treatment processes will contain from 20 to 50 parts per million of oil.

Water treatment equipment includes gravity separators, oil skimmers, gas floatation cells, coalescers, and filters. In addition, chemical treatment may be used to improve the efficiency of water treatment processes, such as floatation, plate coalescers and gravity systems.

Gravity separators and oil skimmers rely on the gravity separation of oil from water. Oil is normally skimmed off the top of these units and water is drawn off the bottom by way of an outside siphon called a "gun barrel." These units are normally used upstream from other oil removal equipment to eliminate the bulk of free oil and sedimentation. Total gravity separation requires a large container and long retention times. The retention allows some gravity separation and dampens surges in volume and oil contact.⁶

Gas floatation units saturate "clean" water with gas in a pressure tower. This water is then mixed with the oil/water mixture in a floatation chamber in which the gas bubbles expand and carry the oil particles to the surface, where they are skimmed off. "Clean" water is then drawn off and discharged with a portion circulated to the gassification pressure tower.⁷

⁶Environmental Protection Agency, Control of Oil and Other Hazardous Materials Training Manual (EPA-430/1-74-005), (Springfield VA: National Technical Information Service, 1974), p. 9-3.

⁷Ibid.

In coalescer units, the water/oil mixture enters a settling section, where heavier solids settle out and free oil rises to the surface. The flow then travels through a graded filter bed, or excelsion section, where oil wetted particles are filtered out. Finely dispersed oil particles are coalesced to the particle size necessary for out-of-the water usage. After filtering, the water passes to a final settling and surge section.⁸

There are two general types of filter equipment, based on the filter medium. These include fibrous media, such as fiberglass, which is usually in the form of a replaceable element or cartridge; and loose media filters, which normally use a bed of granular material such as sand, gravel, or crushed coal. Some filters are designed so that some coalescing and oil removal take place continuously, but a considerable amount of the contaminants (oil and suspended fines) remain on the filter media. This eventually overloads the filter media, requiring its replacement or backwashing. Fibrous media may be cleaned by special techniques or may be replaced. Loose media filters are normally backwashed by forcing water through the bed with the normal direction of flow reversed, or by washing in the normal direction of flow after gassing and loosening the media bed.⁹

Processing of
A Crude
Oil Well Stream

The general pattern of processing a crude oil well stream is to accomplish preliminary steps, such as gas separation and free water removal, offshore first and then pipe the oil-water emulsion to shore for processing. This pattern may change in frontier areas, where distances between offshore platforms and the shore are greater.

⁸ Ibid.

⁹ EPA, Development Document for Interim Final Effluent Limitations Guidelines and New Source Performance Standards for the Offshore Segment of the Oil and Gas Extraction Point Source Category. (Washington, DC: Office of Water and Hazardous Material, U.S. EPA, 1975), p. 8.

gas processing equipment even if natural gas is separated and sold on the platform. This will happen because the crude oil will contain a certain amount of dissolved natural gas because it is under pressure. The amount of natural gas contained in the oil depends on how much gas is removed offshore and the pressure at which the crude is delivered. In some cases, the amount of gas is only sufficient to fuel the facility's processing equipment, while in other cases, there is enough to be sold commercially as well. In some cases, facilities for the recovery of liquid hydrocarbons in the gas stream are constructed, depending upon the quantity of gas present and the "richness" (or liquid hydrocarbon content) of the gas.

CHARACTERISTICS,
REQUIREMENTS
AND IMPACTS

Land Requirements

Partial processing plants require approximately 15 acres of land per 100,000 barrels of oil and associated gas to be processed.¹¹ Typical space requirements for various stages of operations, expressed as percentages of the total 15 acres are as follows:

Oil Treatment	11.4%	1.71 acres
Oil Storage	21.9%	3.28 acres
Gas Treatment	42.1%	6.31 acres
Water Treatment	8.8%	1.32 acree
Liquified Petroleum		
Gas Storage	7.0%	1.05 acres
LACT unit*	8.76%	1.31 acres

*the LACT (Lease Automatic Custody Transfer) unit is an automatic volume metering and recording system which measures and transfers clean oil production from the processing facility to the pipeline or carrier owned or used by the individual producing company.

11 The 15 acres per 100,000 barrels of crude oil assumes that gas processing facilities will be located at the same site. Acreage requirements would be reduced if there is no gas processing.

12 State of California, Governor's Office of Planning and Research, Onshore Impact of Offshore California OCS Sale No. 35 Draft, (Sacramento, 1976), p. III-31.

Special Locational Requirements

Processing facilities have several special locational requirements. They should be located near the pipeline landfall site in order to minimize pipeline construction and operating costs. They need not be located at a waterfront site, but at least within several miles of the coastal site. If the processed crude oil is to be transported by tanker or barge, the proximity to a port of sufficient depth to accommodate the largest expected tanker or barge becomes an important siting criteria. This, in turn, will depend on the distance between the processing facility and the refinery. For shorter distances, it is likely that relatively small barges would be used, while for great distances, larger tankers would be used. Processing plants that transport processed crude oil by pipeline are not sensitive to locating near-ports and are less sensitive to coastal locations, in general.

Waterfront Requirements

Waterfront requirements are an important consideration only if processed crude oil is to be transported by barges or tankers, as mentioned previously. Small tankers and barges, used for short hauls, may require a channel depth of approximately 30 feet. Large tankers, used for long hauls, may require a channel depth of up to 65 feet.

For example, in Southern California, where most of the processed crude is refined locally or regionally, barges and small tankers are used. In Orkney, Scotland, where processing facilities and a marine terminal are located far from densely populated areas and oil refineries, tankers of the 150,000 to 200,000 dead weight ton range and which have drafts of 54 to 60 feet are utilized.

Water Requirements

Partial processing facilities require only small volumes of water. Water is used to heat the crude oil, cool compressors, fight fires, for sanitary uses, and in some cases, for irrigation of plant sites. Water in the crude oil heating system is recirculated and changed only periodically. Cooling water requirements for compressors would be on the order of 100 gallons per day. Fire water would be stored in tanks on the order of 20,000 barrels. Since the plant would be operated by a staff of less than five people, sanitary water requirements would be minimal. Irrigation water is required in arid or semi-arid regions in order to maintain vegetation and prevent erosion. In southern

In Northern Scotland, when large volumes of crude need to be transported relatively long distances, processed crude oil is transported in tankers typically in the range of 60 to 70,000 dwt with a maximum size of 100,000 dwt. The Flotta Terminal in the Orkney Islands is designed to accommodate tankers up to 200,000 dwt.

Site Alteration
and
Construction

Environmental impacts from site alteration and construction of the partial processing facility will vary with the characteristics of the chosen site and the size of the area disturbed. According to one study of partial processing facilities ¹⁶ approximately 10-20 acres will be altered to nonpermeable surfaces, such as roads and storage tanks. During this phase, a reduction in the populations of small mammals, reptiles, amphibians, and birds may result. However, replanting and seeding, where possible, would minimize these impacts by the recreation of destroyed habitats.

If site preparation is timed to coincide with the drier season of the year, and if the selected site is level, with an adequate-sized buffer zone, the subsequent erosion, siltation, and eutrophication should cause minimal ecological disturbances. If the soil at the site contains a high proportion of fine-grained particles, high dust emissions and siltation may result. Since sea coast soils are generally wet and shallow to bedrock, an inland site would require less soil movement, leveling, grading, and bedrock removal.

No unique, heavy machinery or processes are required on the site, so site alteration and construction are not expected to result in severe noise or air pollution. Construction workers' automobile emissions were based on a total mileage of 3,400 miles per day and are presented below:

Pollutant	Tons/Day
carbon monoxide	0.094
hydrocarbons	0.013
nitrogen oxides	0.022

¹⁶U. S. G. S., Final Environmental Statement - Oil and the Santa Barbara Channel, 1976, p. III-182.

Because partial processing facilities are often collocated with pipeline landfalls, gas treatment processing plants and marine terminals, more extensive impacts may result from such alterations as dredging or filling. Site alteration and operational impacts associated with specific collocated facilities may be found in their respective chapters; an overview of site alteration and construction impacts is presented in Appendix B.

Air Emissions

The volume of air emissions from a partial processing facility will be determined by many factors, including the process design of the facility, the type and number of storage tanks and the maintenance of the process system.

Sources of air emissions include:

- evaporative emissions from surge and storage tanks,
- combustion emissions from process machinery and mobile sources, and
- leakage from valves and seals.

Pollution control devices may significantly reduce overall emissions, thereby diminishing the impacts on the surrounding area. However, locating a partial processing facility in a region where ambient concentrations already approach maximum allowable standards, may serve to limit further industrial growth in the area.

Storage Tank Emissions: Hydrocarbon evaporative emissions may result from the two types of storage facilities at a partial processing facility: surge tanks, which store the crude oil-water emulsion prior to partial processing, and storage tanks, which store the oil that has been partially processed. The volume of evaporative losses from storage tanks depends on the following factors:¹⁷

17

All general information on air emissions in the section on storage tanks was taken from U.S. E.P.A., Compilation of Air Pollutant Emission Factors, 2nd edition, 1976.

tank design

- type of roof
- diameter and capacity
- color of surface paint
- mechanical condition of tank

tank location and usage patterns

- diurnal changes in tank vapor space
- schedule of emptying and filling
- height of vapor space
- vapor pressure of stored liquids.

As shown in Figure 4.7, there are three basic tank designs varying primarily by roof type -- fixed roof, floating roof, and variable vapor space. A fixed roof tank is the least expensive to construct; it is equipped with a pressure/vacuum vent which responds to deviations in pressure.

A floating roof tank has a roof which "floats" up and down in response to changing amounts of vapor present. The floating roof prevents the formation of vapor above the liquid surface which would otherwise escape (as emissions) during filling and emptying. The tank is equipped with mechanical seals to seal the space between the roof and the walls. Floating roofs are sometimes covered with fixed roofs to further reduce vapor losses.

A variable vapor space tank is equipped with a diaphragm, or "lifter" roof, which responds to the expansion and contraction of the vapor above the liquid surface.

Emissions from fuel storage tanks fall into three categories: Breathing losses, caused by temperature and pressure changes in the tank, are found only with fixed roof tanks; Working losses, from filling and emptying, are found with both fixed roof and variable vapor space tanks; and Standing storage losses, due to improper fits between seal and tank walls, are found with floating roof tanks.

Table 4.1 shows average hydrocarbon emissions for fixed roof, floating roof, and variable vapor space tanks.

TABLE 4.1
TYPICAL FUEL STORAGE TANK EMISSIONS

<u>Tank Type</u>	<u>Crude Oil Emissions</u> <u>lbs/day-1,000 gals.</u>	<u>Kerosene^a</u> <u>Emissions</u> <u>lbs/day - 1,000 gals.</u>
<u>fixed roof</u>		
breathing loss	0.15	0.036
working loss (lbs/1000 gal. transferred)	7.3	1.00
floating roof (standing storage loss)	0.029	0.005
variable vapor space (working)	not used	1.000

^afigures for kerosene used due to unavailability of figures for diesel oil and the similarity of the two fuels.

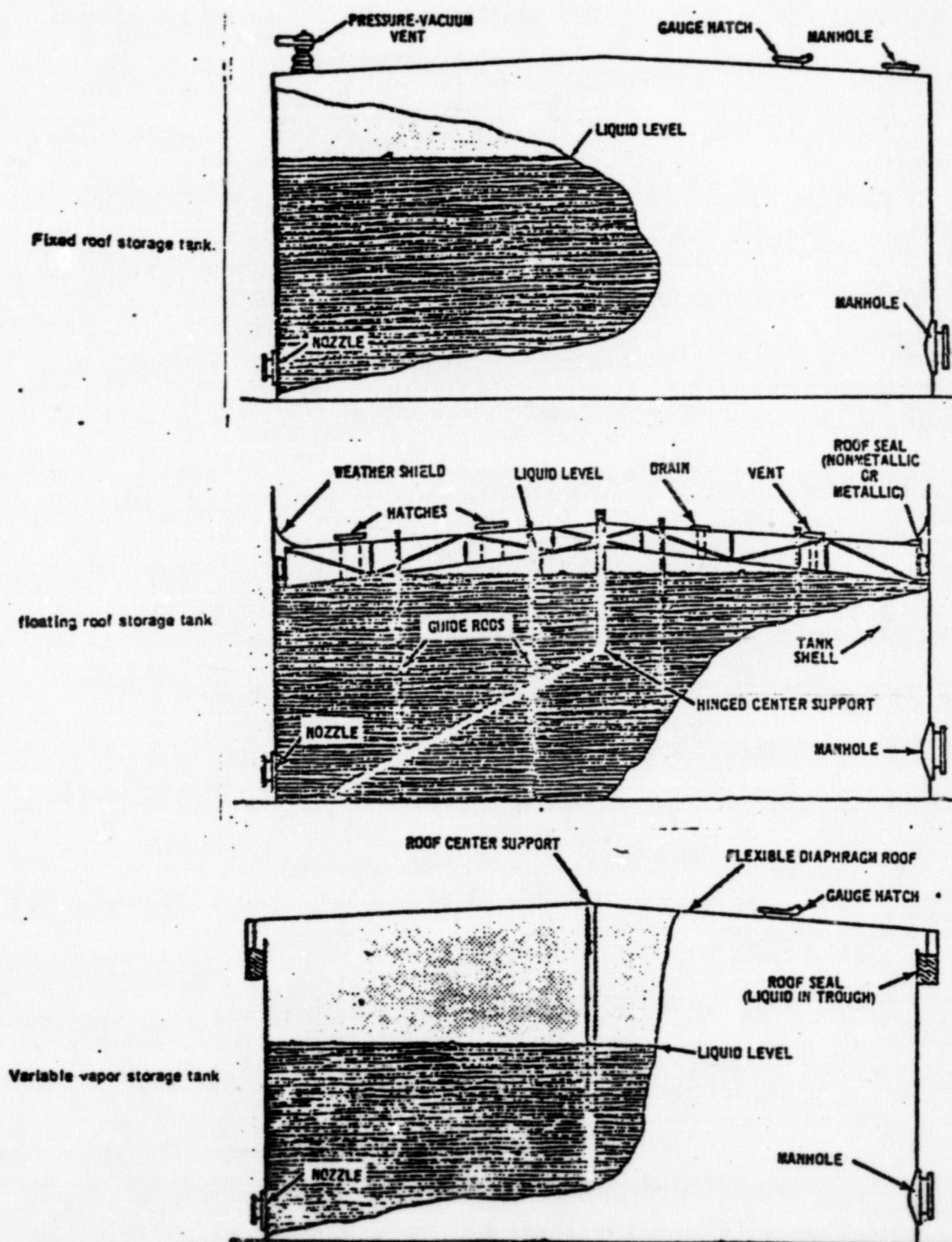
Source: U.S., EPA, Compilation of Air Pollutant Emissions Factors, 2nd edition, 1976, pp. 4.3-8 and 4.3-9.

The American Petroleum Institute has developed a formulae which can be used to calculate these various types of losses for any particular tank.¹⁸ The following is a sample calculation to determine the hydrocarbon breathing loss for a hypothetical fixed roof tank containing crude oil.

¹⁸ A complete list of formulas and variables can be found in U.S., EPA, Compilation of Air Pollutant Emission Factors. 2nd edition, 1976, pp. 3-4 through 4.3-7.

FIGURE 4.7
 FUEL STORAGE TANKS

2864



Source: US, EPA, "Petroleum Storage," Compilation of Air Pollutant Emission Factors, 2nd edition (1975), pp. 4.31 - 4.33.

Fixed roof breathing losses can be estimated from the formula:

$$B = \frac{2.74 WK}{V_c} \left(\frac{P}{14.7 - P} \right)^{0.68} D^{1.73} H^{0.51} T^{0.50} F_p C$$

where:

B = Breathing loss, lb/day-10³ gal. capacity

P = True vapor pressure at bulk liquid temperature, psia (4.6)

D = Tank diameter, feet (90)

H = Average vapor space height, including correction for roof volume, feet (11)

T = Average daily ambient temperature change, °F (15)

F_p = Paint factor (1.00)

C = Adjustment factor for tanks smaller than 20 feet in diameter

V_c = Capacity of tank, barrels (50,000)

K = Factor dependent on liquid stored (0.014)

W = Density of liquid at storage conditions, lbs/gal. (7.08)

Breathing loss emissions for this hypothetical fixed roof tank containing crude oil are equal to 0.1 lbs/day per 1,000 gallons stored.

Certain pollution control devices may be used to limit the volume of evaporative emissions resulting from the storage of petroleum products. Two proposed partial processing facilities¹⁹ have included the following control methods in their facility designs:

¹⁹U.S. G. S., Final Environmental Statement - Oil and Gas Development in the Santa Barbara Channel, 1976, and

U.S. G. S., Final Environmental Statement - Proposed Plan of Development Santa Ynez Unit, 1974.

- use of high operating pressures which reduces the vapor pressure of the oil portion of the oil/water emulsion and thus, the evolution of hydrocarbon vapors;
- exclusive use of floating roof-type tank design equipped with closed covers to trap vapors; and
- all emissions, including evaporative losses and losses from vent, relief and/or blowdown lines, routed to a vapor recovery incinerator.

A vapor recovery incinerator eliminates any direct venting of evaporative or operational emissions to the atmosphere. When emissions are incinerated in the presence of excess air, any hydrogen sulfide present is converted to sulfur dioxide and hydrocarbons to water and carbon dioxide. These emissions, in addition to nitrogen oxide gases, are vented to the atmosphere through a smokestack.

One of these proposed facilities²⁰ has two surge tanks, four crude oil storage tanks and processes 80,000 barrels per day. Twenty-two pounds of sulfur oxides and four pounds of nitrogen oxides are emitted daily.

Combustion Emissions: Treating vessels to separate the oil/water emulsion by heat and electrostatic action in a direct fire combustion method. If sweet natural gas is utilized in the presence of excess air, hydrocarbon and carbon monoxide emissions may be minimized.

Emissions may also be collected and routed to a vapor incinerator recovery system. Emissions from a proposed facility with eight treating vessels are estimated to include: ²¹

4.8 lbs/day of sulfur oxides, and
152 lbs/day of nitrogen oxides.

²⁰ U.S.G.S., Santa Barbara, Environmental Impact Statement, 1976, pp. III-194.

²¹ Ibid.

Leakage: Leakage from pumps and valves may cause chronic low level hydrocarbon emissions at and around the site of a partial processing facility. Pumps may be fitted with dual seals to lower emissions from these sources. In addition, a program of constant equipment maintenance and repair may minimize the volume of these emissions. Process leakage from the proposed Santa Barbara²² partial processing facility are 36 lbs/day of hydrocarbons and one lb of hydrogen sulfide per day.

Total emissions from the proposed 80,000 barrel facility at Santa Barbara are summarized in Table 4.2.

TABLE 4.2

AIR EMISSIONS FROM AN 80,000
BARREL PER DAY PARTIAL
PROCESSING FACILITY

tons/year

Source	Hydrocarbons	Hydrogen Sulfide	Sulfur Oxides	Nitrogen Oxides
crude oil heaters (8 units)	0	0	0.88	27.7
vent vapor incinerator	0	0	4.	0.7
process leaks	6.6	0.2	0	0

Source: U. S. G. S., Final Environmental Statement - Oil and Gas Development in the Santa Barbara Outer Continental Shelf Off California, 1976, Vol. II, P. III-194.

²² Ibid.

Partial processing plants may require the use of pumps to maintain the high pressures necessary for the separation procedure. If gasoline is used as fuel, the major emissions would be carbon monoxide and hydrocarbons; if diesel fuel is used, major emissions would be nitrogen oxides and exhaust hydrocarbons. Table 4.3 presents average emissions factors for industrial equipment.

TABLE 4.3
EMISSIONS FACTORS FOR
INDUSTRIAL EQUIPMENT ENGINES

Pollutant	Gasoline	Diesel
<u>Carbon monoxide</u>		
pounds/hr	12.6	0.434
pounds/1000 gal.	3940	102.
<u>Exhaust hydrocarbons</u>		
pounds/hr	0.421	0.160
pounds/1000 gal.	132.	37.5
<u>Nitrogen oxides</u>		
pounds/hr	0.326	2.1
pounds/1000 gal.	102.	469
<u>Sulfur oxides</u>		
pounds/hr	0.017	0.133
pounds/1000 gal.	5.31	31.2
<u>Particulates</u>		
pounds/hr	0.021	0.143
pounds/1000 gal.	6.47	33.5

- Source: EPA, Compilation of Air Pollutant Emissions Factors, pp. 3.3.3-2

Vehicle emissions from trucks and employee automobile traffic can be expected to add primarily carbon monoxide, hydrocarbons, and nitrogen oxides to the air, both at the site and along nearby highways. Emissions from these vehicles must meet the current federal standards presented in Appendix C.

The operation of a partial processing facility will generate the following types of wastewater:

- produced water (brine),
- runoff water,
- cooling water,
- boiler water,
- domestic wastewater.

Produced Water: Treatment at a partial processing facility normally involves the separation of the oil/water emulsion, which is a constituent of the well stream as it leaves the ground. The wastewater (brine) from this process often contains high concentrations of suspended and dissolved solids and heavy metals, as much as 5,000 parts per million (ppm) of dissolved salts and 200 to 300 ppm of oil. Table 4.4. and 4.5 illustrate the types and concentrations of these pollutants in two petroleum development regions.

TABLE 4.4
POLLUTANTS IN PRODUCED WATER
Louisiana Coastal (a)

<u>Pollutant Parameter</u>	<u>Range mg/l</u>	<u>Average mg/l</u>
Oil and grease	7 - 1300	202
Cadmium	0.005 - .675	0.068
Cyanide	0.01 - 0.01	0.01
Mercury	---	0.0005
Total Organic Carbon	30 - 1580	413
Total suspended solids	22 - 390	73
Total dissolved solids	32,000 - 202,000	110,000
Chlorides	10,000 - 115,000	61,000
Flow	250-200,000 bbls/day	15,000 bbls/day

(a) results of 1974 EPA Survey of 25 discharges

Source: EPA, Development Document for Interim Final Effluent Limitations Guidelines and New Source Standards for the Offshore Segment of Oil and Gas Extraction Point Source Category, Sept. 1975,

TABLE 4.5

POLLUTANTS CONTAINED IN PRODUCED WATER

Coastal California (a) (7)

<u>Pollutant Parameter</u>	<u>Range, mg/l</u>
Arsenic	0.001 - 0.08
Cadmium	0.02 - 0.18
Total Chromium	0.02 - 0.04
Copper	0.05 - 0.116
Lead	0.0 - 0.28
Mercury	0.0005- 0.002
Nickel	0.100 - 0.29
Silver	0.03
Zinc	0.05 - 3.2
Cyanide	0.0 0.004
Phenolic Compounds	0.35 - 2.10
BOD	370 - 1,920
COD	400 - 3,000
Chlorides	17,230 - 21,000
TDS	21,700 - 40,400
Suspended Solids	
Effluent	1 - 60
Influent	30 - 75
Oil and Grease	56 - 359

(a) Some data reflect treated waters for reinjection.

Source: EPA, Development Document for Interim Final
Effluent Limitations, P. 45.

Prior to discharge, this effluent must be treated to remove some of these impurities. Various treatment methods are utilized to remove oil and grease and particulate matter. There is no treatment method currently in use for removal of dissolved substances such as salts and heavy metals.

Four basic types of treatment are currently used to remove oil and suspended solids from produced water:

- gas flotation
- coalescing systems
- filter systems, and
- gravity separation.

In the gas flotation system, bubbles are injected into the wastewater. As the bubbles rise, oil adheres to their surfaces and is skimmed off when they reach the surface. The coalescing method uses a system of tile plates, which also act as adhesion bases on which the oil coalesces. Filter systems may utilize either fibrous or loose media to trap the oil and particulates. Gravity separators are large tanks or pits in which the oil and particulates are allowed to settle by separation. Chemicals which are surface active, coagulating or polyelectrolytic may be added to increase the efficiency of the method chosen. Table 4.6 compares the relative performance of these treatment methods.

TABLE 4.6

PERFORMANCE OF BRINE TREATMENT
SYSTEMS

<u>Type Treatment System</u>	<u>Mean Effluent, Oil and Grease mg/l</u>
Gas Flotation	27
Parallel Plate Coalescers	48
Filters	
Loose Media	21
Fibrous Media	38
Gravity Separation (4)	
Pits	35
Tanks	42

Source: EPA, Development Document for Interim Final
Effluent Limitations

The volume, types and concentrations of various pollutants contained in produced water vary greatly from stream to stream. A survey of water discharges produced after treatment in California²³ calculated average constituent concentrations of oil field brine in milligrams per liter:

Total suspended solids	60 mg/l
Oil and grease	12 mg/l
Chemical Oxygen Demand	3000 mg/l

Figure 4.8 and Table 4.7 present the effluent characteristics of a partial processing facility in California. The average wastewater discharge rate is approximately 36,000 gallons per day.

Table 4.8 presents the volumes of pollutants discharged from two partial processing facilities, one in Louisiana and one in California. At the Louisiana facility, the oil water emulsion is first broken in heater treaters, to which emulsion breaking chemicals have been added. Wastewater is treated by settling and further addition of chemicals. Prior to discharge, the wastewater is also filtered. Average daily effluent volume is approximately 1.5 million gallons.

In the California facility, three separation methods are used in parallel streams. The first stream utilizes a skimmer followed by a gas flotation cell. The second stream is initially treated by passage through a diatomaceous earth filter, after which it enters a gas flotation cell for further removal. The third stream uses a series of settling tanks, gas flotation cells, and skimmer tanks to remove oil and particulates. The streams are then combined and discharged at a rate of 1.05 million gallons per day.

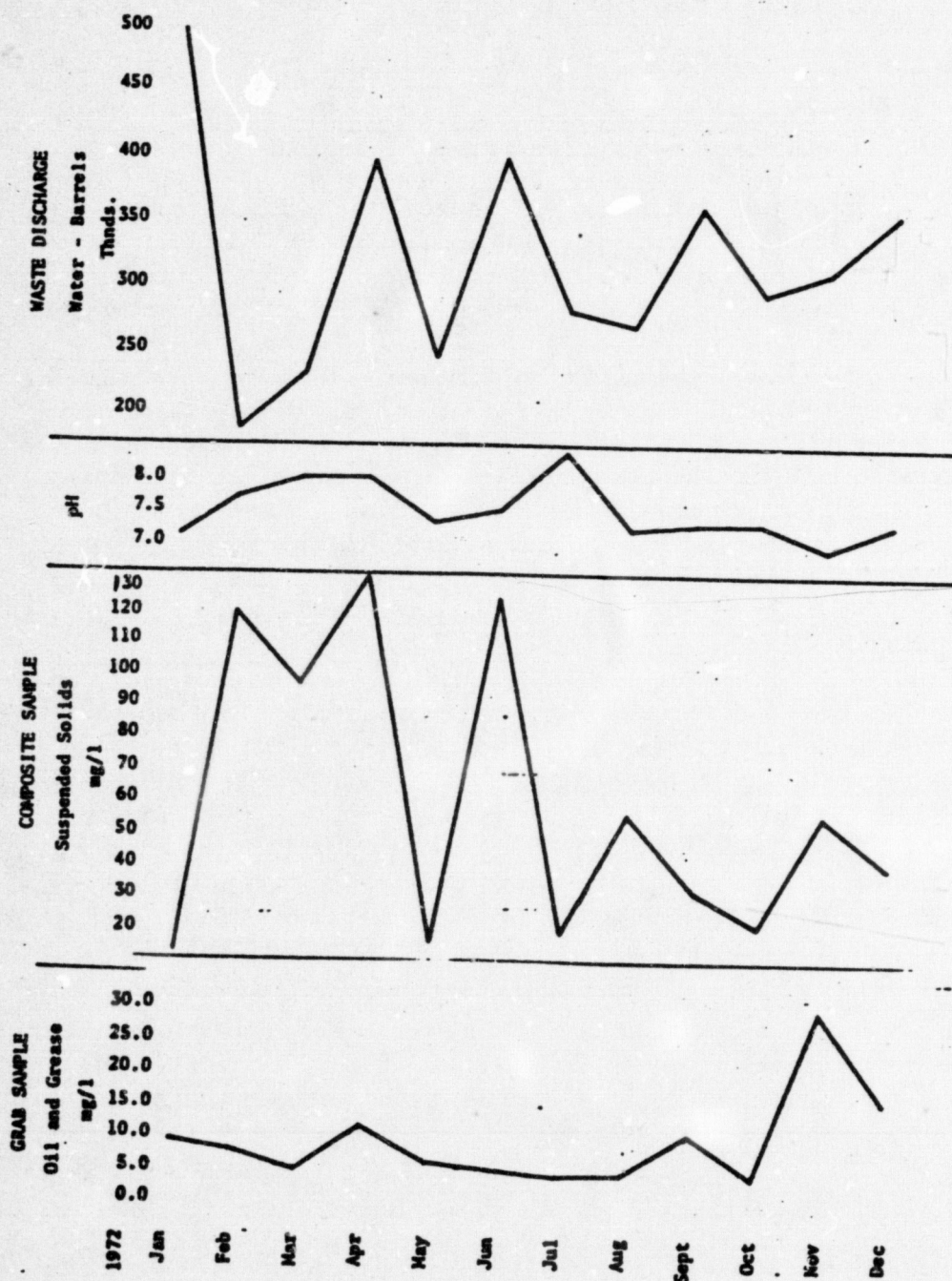
²³ Ibid. p. II-603.

2873

4.39

FIGURE 4.8

MONITORING DATA
PHILLIPS PETROLEUM COMPANY LA CONCHITA ONSHORE
FACILITY, VENTURA COUNTY



Source: U.S.G.S., Final Environmental Statement, Oil and Gas Development in the Santa Barbara Channel, 1976, pp. II-615.

TABLE 4.7

TYPICAL CHARACTERISTICS OF EFFLUENT FROM WATER TREATMENT FACILITIES

Phillips Petroleum Company			
Lease OCS-P 0166 - La Conchita Plant			
Physical Properties		Chemical Properties, mg/l	
pH	7.3	Aluminum	2.2
Specific Gravity	1.02	Ammonia, N	39.7
Turbidity	12 JTU	Arsenic	0.001
Total Dissolved Solids (Calc.)	40,400 mg/l	Barium	0.
Total Solids	20,990 mg/l	Bromide	183.8
Total Volatile Solids	1810 mg/l	Cadmium	0.030
Total Suspended Solids	56 mg/l	Chromium	0.020
Settleable Solids	0.1 mg/l	Copper	0.116
Floatable Solids	0.3 mg/l	Cyanide	0.004
Temperature	77°F	Fluoride	1.7
		Iron	1.35
		Lead	0.28
Specific Conductance	31,630 m-mhos/cm		
Max. CaSO ₄ Possible (Calc.)	0. mg/l	Magnesium	50.0
Max. BaSO ₄ Possible (Calc.)	0. mg/l	Manganese	0.062
Alkalinity as CaCO ₃	3480 mg/l	Mercury	0.0005
		Nickel	0.29
<u>Dissolved Solids</u>		Nitrate, N	0.0
<u>Cations</u>		Nitrate, N	0.000
Total Hardness	10 me/l	Kjeldahl Nitrogen	54.6
Sodium, Na ⁺ (Calc.)	15,000 mg/l	Phosphorus-Ortho, P	1.54
Calcium, Ca ⁺⁺	80 mg/l	Phosphorus, P	1.89
Magnesium, Mg ⁺⁺	72 mg/l	Silver	0.030
Iron (Total), Fe ⁺⁺⁺	1.0 mg/l	Zinc	0.18
<u>Anions</u>		Phenolic Compounds	
Chloride, Cl ⁻	21,000 mg/l	C6H5OH	2.10
		Identifiable	
Sulfate, SO ₄ ⁼	0. mg/l	Chlorinated	None
Carbonate, CO ₃ ⁼	0. mg/l	Hydrocarbons	
Bicarbonate, HCO ₃ ⁻	4,270 mg/l	Radioactivity	
		Gross Alpha Activity	None Detected
Hydroxyl, OH ⁻	0. mg/l	Gross Beta Activity	None Detected
		Oil and Grease	5.0
Sulfide, S ⁼	1.1 mg/l		
<u>Dissolved Gases</u>			
H ₂ S	0.4 mg/l		
CO ₂	320 mg/l		
O ₂	0.3 mg/l		

Source: U.S.G.S., Santa Barbara EIS, pp. II-616.

TABLE 4.8

EFFLUENT CHARACTERISTICS OF TWO PARTIAL
PROCESSING FACILITIES

<u>Pollutant</u>	average lbs/day	
	<u>Louisiana</u>	<u>California</u>
Biochemical Oxygen Demand (5 day)	14,952	7,375
Chemical Oxygen Demand	30,664	16,691
Total Suspended Solids	412	790
Oil and grease	522	158
Alkalinity	12,412	10,250
Ammonia	318	306
Kiekdahl nitrogen	326	342
Total Phosphorus	3.5	0.74
Total Hardness ($\text{Ca}^{\text{as}} \text{CO}_3$)	77,420	12,355
Sulfate	222	787
Bromide	127	936
Chloride	494,009	91,000
Fluoride	7.8	17.5
Barium	671	116
Boron	----	569
Calcium	17,518	2,739
Chromium	<1.9	0.18
Copper	<2.53	0.26
Iron	143	7
Magnesium	8,181	1,339
Potassium	2,153	543
Sodium	316,623	74,086
Phenols	47	24.5

- Source: 1. Army Corps of Engineers Permit # - LMN OK K 2
000142 - Continental Oil Company, Grand Isle, LA.
2. Army Corps of Engineers Permit # 075 OYQ 2
000072 4073 - Shell Oil Company, Ventura, CA.

Because of the high concentrations of potentially toxic pollutants contained in produced water, its disposal must be handled with care. Discharges into coastal waters (up to three miles offshore) are currently regulated by the individual states. Regulations on discharges of brine in federal waters are currently under study by the U.S. Environmental Protection Agency. Table 4.9 presents effluent limitation guidelines for new sources issued by the EPA in September 1975.

TABLE 4.9

EFFLUENT LIMITATION GUIDELINES
FOR PRODUCED WATER

	<u>oil and grease mg/l</u>	
	maximum for one day	average of 30 consecutive days shall not exceed
Near Offshore	no discharge	no discharge
Far Offshore	52	30

Source: EPA, Development Document for Interim Final Limitations, p. 5.

Currently favored disposal methods are reinjection of produced water in an offshore well or surface discharge in far offshore areas.

The environmental impacts associated with oil and heavy metal pollution in the marine environment include both toxic and sublethal responses. Juvenile forms of many species of marine fauna are particularly sensitive, and an age class may be totally eliminated by a specific dosage of oil or some heavy metal. Sublethal physiological alterations include depression of growth and photosynthesis in marine flora. In addition, heavy metals may accumulate in

the tissues of lower organisms on a food chain, exerting lethal effects at some higher level in the chain. Specific dose-effect relationship for oil and heavy metals are found in Appendix A, Tables 3 and 4.

Runoff: Storm water runoff from a partial processing facility may contain accidentally spilled contaminants, such as oil and brine. Dykes may be constructed around individual storage tanks or tank areas, which serve the purpose of containing major spills or leaks, and as a form of fire protection. This dyking may be required by state or local law; however, it is considered from the viewpoint of fire prevention rather than as a means of containing contaminated runoff water. No water quality restrictions currently exist for runoff at this facility.

Any runoff which leaves the site and reaches surface or subsurface waters will likely be industrial in nature, and will contaminate receiving waters.

Cooling Water: Cooling water may be required for pumps and other process machinery at a partial processing facility. The volume will depend on the number of machinery units using cooling water and the type of cooling system employed.

If the thermal discharges from a partial processing facility are combined with thermal discharges from other related co-located facilities (such as cooling water from a gas processing plant), large net increases in receiving water temperature may result. Significant alterations in ambient water temperatures can cause lethal thermal shock in sensitive indigenous flora and fauna. Temperature increases may also alter the chemical nature of the water by reducing the solubility of gases and increasing the solubility of heavy metals and other toxic substances. (Specific dose-effects relationships are found in Appendix A, Tables 4.5.)

Besides the added heat, cooling water may also contain dissolved solids and biocides, which are added to prevent equipment corrosion and fouling. The chemicals used and the concentrations maintained in the cooling system are shown in Table 4.10.

4.44

Characteristics, Requirements, and Impacts (continued)

TABLE 4.10

CHEMICALS ADDED TO COOLING WATER

<u>Chemical</u>	<u>Concentration Maintained</u>
Sulfuric Acid enough to maintain	pH approx. 7
Chromate	30 ppm
Zinc	3 ppm
Chlorine	0.1 - 0.2 ppm

Source: Testimony of F. W. Wheeler for the Texas Oil and Gas Association, 8/17/73.

Heavy metals, such as chromate and zinc, are toxic to some aquatic organisms. Detailed information on heavy metal and chlorine pollution may be found in Appendix A, Table 4. Maximum effluent discharges must fall within the discharge limits established by the National Pollution Discharge Elimination System (NPDES).

Boiler Water: Water used in steam generation at the partial processing facility is initially preconditioned to remove suspended solids and hardness, and may even be deionized before entering the boiler. The specific chemicals added to boiler water to minimize corrosion, sludge, and scale are shown in Table 4.11.

4.45
Characteristics, Requirements, and Impacts (continued)

TABLE 4.11

CHEMICALS ADDED TO BOILER WATER TO REDUCE
CORROSION, SCALE, AND SLUDGE

<u>Chemical</u>	<u>Concentration Maintained</u>
Phosphate	20-60 ppm
Bases enough to maintain	pH 10.2-10.6
Sulfite ^a	20 ppm
Sludge conditioners ^b	20 ppm

^ato reduce dissolved oxygen

^be.g., tannins, lignins, starch organics

Source: Testimony of F.W. Wheeler for Texas Oil and Gas Association, 8/17/73.

Domestic Wastewater: The amount of wastewater will be proportional to the number of employees at the facility. The wastes can be collected and delivered to a municipal treatment plant or may be processed at the site. In either case, the discharge will have to meet the standards of the receiving waters.

Noise Impacts:

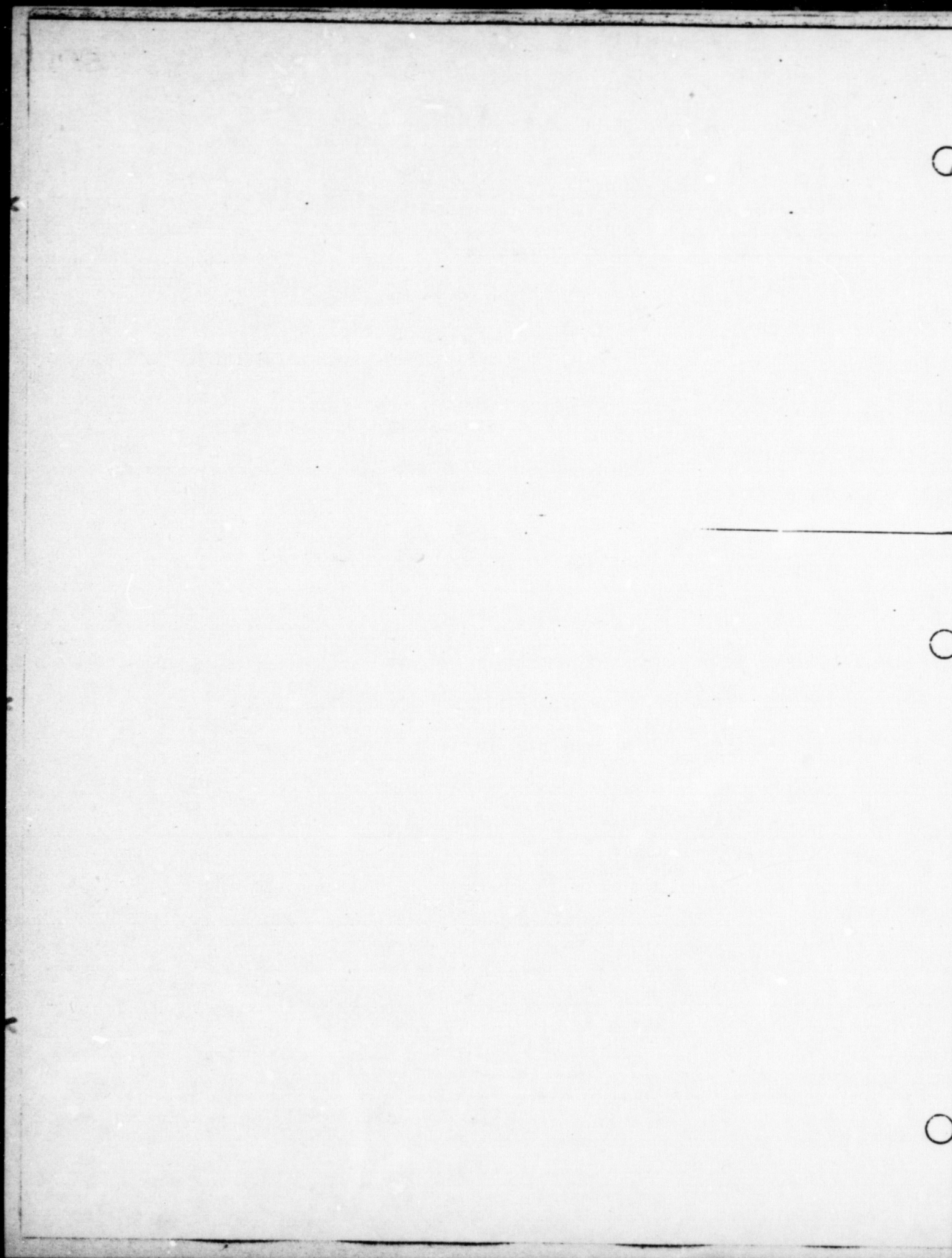
Noise at a partial processing facility comes from the pumps used to maintain high operating pressures, flarestacks at vapor incinerators and the treating vessels used for oil/water separation. Noise levels and appropriate control devices are presented in Table 4.12.

GAS PROCESSING AND TREATMENT PLANTS

SUMMARY OF REQUIREMENTS AND IMPACTS

Unless otherwise noted, statistics are for a billion cu. ft./day plant

Land:	50 to 75 acres		
Water:	200,000 gallons per day average		
Energy:	5,400,000 kilowatt hours/month 360,000,000 cubic feet/month of natural gas from plant		
Labor:	550 construction jobs (peak figure) 45-55 operation and maintenance jobs		
Wages:	approximately \$750,000 per year (operation and maintenance)		
Capital Investment:	\$85 million (one billion cu. ft./day plant) \$26 million (300 million cu. ft./day plant)		
Construction Period:	1.5 years		
Air Emissions:	<u>major</u>	<u>minor</u>	
	hydrogen sulfide	particulates	
	sulfur oxides	carbon monoxide	
	hydrocarbons	nitrogen oxides	
Wastewater Contaminants:	in cooling water:	sulfuric acid	
		chromium	30 ppm
		zinc	3 ppm
		chlorine	0.2 ppm
	in boiler water:	phosphates	20-60 ppm
		bases	
		sulfite	20 ppm
	general:	dissolved hydrocarbons	
Noise:	80-100 decibels from boilers, compressors, and flare-stacks on a 24-hour basis		
Solid Wastes:	Scale and Sludge from boiler and cooling tower cleanouts; tank cleaning sludge; spent dessicants, filtration media and oil absorbants.		



*Timing, Trends, and Options (continued)*The Market for Liquid
Hydrocarbons

After liquifiable hydrocarbons have been recovered and impurities removed, the gas enters a commercial transmission line for distribution. The liquid hydrocarbon stream is then fractionated (separated into its major components). This may take place at the same site as recovery, or the entire stream may be transported to a centralized fractionation facility, which may handle the output of several recovery plants. Fractionation facilities may be designed for any volume, although typical facilities will range from five to 50,000 barrels per day.

The components of the liquid hydrocarbon stream after fractionation are ethane, propane, butane, and heavier hydrocarbons. Propane is usually sold to bottled gas distributors. Butane and heavier hydrocarbons are usually delivered to a refinery as feedstock. Ethane may not be recovered if no market for it exists, since it is the most difficult liquid hydrocarbon to recover. It is generally used as petrochemical plant feed stock.

The nature of gas processing facilities will vary depending on which hydrocarbons will be recovered and whether or not fractionation will take place at the same location. For example, the special refrigeration process needed to recover ethane would not be incorporated into a gas plant design unless a market for ethane existed within a reasonable distance from the plant.

Relationship Between
Gas Plants and
Petrochemical Plants

Petrochemical plants have been built in areas in close proximity to large reserves of natural gas. Such a plant uses ethane produced by the gas plant as feedstock. However, a gas find in a frontier region would have to be extremely large in order for a petrochemical plant to become an economically viable proposition. Approximately 27,000 barrels per day of liquid hydrocarbons with a high percentage of ethane would be required to support a billion pound per year ethylene plant. This large volume must also be sustained for ten to fifteen years to justify the location of an ethylene plant. The establishment of a large ethylene plant may induce additional downstream petrochemical activities to locate in the region.

CHARACTERISTICS,
REQUIREMENTS,
AND IMPACTS

Land Requirements

The amount of land required for a gas plant is related but not directly proportional to throughput capacity. Land (preferably flat and well-drained) is required for buildings, storage facilities, pipes, towers, compressors, buffer zones, and parking lots. Actual space required for processing is very small; much more space is required for safety reasons. The process, loading, utility, storage, and office areas are usually separated, with extra land around the plant perimeter. A typical billion cu. ft. /day plant might require a total of 75 acres, of which 20 might be used for buildings and structures. For planning purposes, 50 to 75 acres would be required for a gas plant processing 200 to 1,000 million cu. ft. /day.

Onshore partial processing facilities may be established to process natural gas and/or oil. A combined partial processing facility requires approximately 15 acres of land per 100,000 barrels of oil and associated gas processed.

Special Locational
Requirements

A gas plant must be sited somewhere between the gas pipeline landfall where the pipeline joins other commercial gas transmission lines. The availability of land along this route is a primary determinant in plant siting, as are local land use patterns and regulations.

There are several factors which may lead to the selection of a coastal site. In some cases, a control complex of a gas plant will also control offshore production wells through the use of U.H.F. telemetry in addition to controlling the flow of gas through the pipeline. When this is the case it is desirable that the control ~~should~~ be situated as close to the coast as possible in order to ensure maximum efficiency and reliability of the overall operation since the U.H.F. system requires line of sight communication. However, industry sources state that if a coastal site is not available, the towers required for the communication system can be located at a site with a relatively high elevation near the coast (or even on a tall building) and connected to the control facility by a regular telephone line.

Characteristics, Requirements, and Impacts (continued)

Because gas cools along its passage from the production platform to shore, causing liquids to form in the line, it is operationally desirable to convert to single phase flow as soon as possible by removing all liquids. Since this can not be done offshore, the coastal site is the first place where it is possible to remove the liquids.

Once gas is treated to remove all liquids, the transmission of the same volume of gas requires far less pipeline capacity. Since larger pipelines can be constructed on land than under the sea, it is likely that the gas from a number of different incoming gas lines to a terminal may be transported in a single, large pipeline after it has been processed. This reduces the costs of pipeline construction and reduces the amount of land required for pipeline.

A coastal location for a gas plant would also minimize the costs of constructing return lines back to the coast, some carrying chemicals to the production field and others returning the salt water extracted from the gas.

In some cases, the economic advantages to coastal locations may be outweighed by the high cost of coastal land or by other factors including land use control regulations.

Water Requirements

Figures available from the gas processing industry in 1973 indicated a water demand for gas plants ranging from zero to 750,000 gallons per day, with most plants using less than 200,000 gallons per day depending on the design of the plant. A typical plant uses about 1.5 gallons of water per thousand cubic feet of gas processed.² The total water requirement for a gas plant varies depending on the cooling process used; an air-cooled system uses much less than a water-cooled system.

² Testimony of F.W. Wheeler for Texas Mid-Continental Oil and Gas Association as presented to Texas Railroad Commission on 8/17/73, p. 3.

However, a modern design would probably utilize an air cooled system with minimal water requirements. Water used may be obtained from wells, bodies of water, or the nearest available municipal water system.

Energy Requirements

A billion cu. ft. / day gas plant would require approximately 5,400,000 kilowatt hours of electricity per month and would have an average load of 7,500 kilowatts, depending on the power system used. Electric power could be purchased from a local utility or generated at the gas plant, depending upon which alternative is less expensive. The plant would also consume 360 million cubic feet of natural gas per month from its feedstock, to fuel heaters and compressors.

Transportation Requirements

The gas plant product yield per day to be transported depends on the volume of gas handled, the liquid content of the inlet gas, and the efficiency of recovery.

Gas plant products are transported by rail, truck, pipeline, or barge, depending upon what type of transportation is available and the location of markets for a particular product. If the gas plant has no fractionation facilities, the product is piped to a fractionation plant. For example, a fractionation plant in Kansas receives unfractionated liquid hydrocarbons by pipeline from several small gas plants in the Southwest. Heavier fractions are normally returned to a liquid pipeline for transport with crude oil to a refinery. The lighter fractions are stored and shipped by rail or pipeline to intermediate users, such as chemical complexes. Small plants might have products shipped by truck, but rail or pipelines are generally more economical for large product volumes. A fractionation plant may be located near water to facilitate barge shipment of products, depending on availability of access and location of markets.

5.18

Characteristics, Requirements, and Impacts (continued)

If the period of site preparation is timed to coincide with the drier portion of the year, and if a level site with an adequate-sized buffer zone is selected, erosion, siltation, and eutrophication should cause minimal ecological disturbance. If the soil at the site contains a high proportion of fine-grained particles, high dust emissions and siltation may occur. Sea coast soils are generally wet and are often shallow to bedrock; and inland site would require less soil movement, leveling, grading, and bedrock removal.

No unique, heavy machinery or processes are required on the site, so site alteration and construction are not expected to result in severe noise or air pollution. It also appears that no unique environmentally sensitive construction materials or methods are required; therefore, no special attention need be focused on the facility construction phase.

Temporary sewage treatment facilities to serve the labor force of up to 500 day laborers will be installed on the site; no serious environmental problems should occur on a 75 acre site from sewage wastes. Solid wastes from construction, including trees and brush, refuse and scrap metal, will be either buried at the site or trucked to a local landfill for incineration and/or burial.

In addition to building the plant, impacts can also be expected from installation of pipelines, roads and/or burial.

*Characteristics, Requirements, and Impacts (continued)*Air Emissions

The magnitude of air emissions, and all other environmental impacts from the operation of a gas plant will depend upon the volume of gas processed, the composition of the raw gas, the plant design, and the pollution control equipment installed.

Sources of air emissions at gas plants include:

- processing;
- evaporation;
- flaring; and
- combustion from machinery and vehicles.

The magnitude of impacts from these sources will largely be determined by the ambient air conditions. In regions where ambient concentrations approach maximum standard concentrations, a gas plant could add sufficient emissions to limit further industrial growth in the area. In an area where air quality is good and concentrations of pollutants are low, impacts will be less severe. The quantity of emissions in either situation will be determined in large part by the pollution controls at the plant, as well as the extent to which regulations are enforced in the area.

Processing Emissions and Controls. If hydrogen sulfide is present in the natural gas stream in economically valuable concentrations, a sulfur recovery process will be included in the gas processing plant. This process uses Claus converters, and recovers 92-97 percent of the sulfur, originally present in the gas stream as hydrogen sulfide. Tail gases from this recovery operation, containing varying amounts of hydrogen sulfide are burned, converting the hydrogen sulfide to sulfur dioxide (SO_2). (Fuel is added to ensure complete conversion.) Sulfur dioxide gases are then vented

Characteristics, Requirements, and Impacts (continued)

through a stack to the atmosphere. The quantity of sulfur dioxide emissions is directly related to the hydrogen sulfide concentration in the gas being processed⁴ and to the volume of gas processed.⁵

Emissions of sulfur dioxide from tail gases can be lessened by the addition of conversion units which reconvert the sulfur dioxide wastes to elemental sulfur. Such processes, combined with the earlier recovery process can result in a sulfur recovery rate of up to 99.9 percent. A non-controlled plant (one which uses Claus converters but does not use sulfur dioxide conversion units) can yield 124-348 pounds of sulfur dioxide emissions per ton of sulfur processed. The actual quantity of emissions depends on the number of Claus converters used for sulfur recovery, as shown in Table 5.2.

TABLE 5.2
EMMISSION FACTORS FOR SULFUR PLANTS
USING CLAUS CONVERTERS

Number of Claus Converters	Recovery of Sulfur, %	SO ₂ Emissions lb/ton
Two, uncontrolled	92 to 95	211 to 348
Three, uncontrolled	95 to 96	167 to 211
Four, uncontrolled	96 to 97	124 to 167
SO ₂ conversion process	99.9	4.0

Source: EPA Compilation of Air Pollutant Emission Factors, 2nd ed., 1976, p. 5.12-2.

⁴ Ecology Audits, Inc. Atmospheric Emissions of the Sour Gas Processing Industry, prepared for EPA Office of Air Quality Planning and Standards, 1975, p. 30.

⁵ State of California Air Resources Board, "Summary of Emissions from Southern California OCS and Santa Barbara OCS Development", Sacramento, California 1975, (unnumbered).

Characteristics, Requirements, and Impacts (continued)

One study⁶ showed that controls could limit SO₂ emission concentrations to less than 2,000 ppm. This quantity fell within the relatively strict local regulations in an area where a plant was to be located in California.

Negligible concentrations of nitrogen oxides (NO_x), particulate matter, and hydrocarbons are found in incineration emissions.⁷ However, under non-optimal incineration conditions, the quantity of these emissions would increase.

Evaporative Emissions and Controls. A study based on two proposed gas treatment facilities⁸ states that evaporative emissions of hydrogen sulfide increase proportionately with increasing amounts of gas processed. Controls can be placed at sources of these emissions, such as control valves or vessel drainage points. Vapors collected at these points are reprocessed through the sulfur recovery facility.⁹

Evaporative losses of hydrocarbons can also be expected during gas processing. These emissions occur at leakage points (such as valves) and increase proportionately with the volume of gas processed.¹⁰

⁶ USGS, Final Environmental Statement-Proposed Plan of Development Santa Ynez Unit, Santa Barbara Channel off California, 1974, Vol. II. P.III-183.

⁷ Ecology Audits, Inc., pp. 36-37.

⁸ State of California Air Resources Board, (unnumbered).

⁹ Ibid.

¹⁰ Ibid.

Characteristics, Requirements, and Impacts (continued)

Flaring. In an emergency situation during sulfur recovery, flaring of tail gas, without the addition of fuel normally used in the incineration process, could take place. In this event, hydrogen sulfide emissions would increase due to less efficient combustion. There is no current federal standard for flaring emissions. 11

A summary of estimated process and evaporative emissions from two proposed gas plant facilities is presented in Table 5.3. The hydrogen sulfide content of the raw gas is assumed to be 0.9% by volume. Sulfur removal efficiency is assumed to be 99.3%.

TABLE 5.3
ESTIMATED PROCESS EMISSIONS FROM TWO
GAS PROCESSING PLANTS *

Source	Plant A (throughput 100 million cu. ft. /day)	Plant B (throughput 1.3 billion cu. ft. /day)
Sulfur Recovery Process (SO ₂)	0.53 tons/day	6.63 tons/day
hydrogen sulfide (H ₂ S) evaporative emissions	0.13 tons/day	1.65 tons/day
hydrocarbon evaporative emissions	10.50 tons/day	131.04 tons/day

Source: State of California Air Resources Board,
"Summary of Emissions from Southern California
OCS and Santa Barbara Channel OCS Development", 1975.

*According to industry comments, figures in Table 5.3 appears to be high with respect to a modern gas processing plant. The Western Oil and Gas Association (WOGA) is making a study to establish the validity of the data furnished by the State of California Air Resources Board.

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11. Conversation with Bill Herring, Director, Oil and Natural Gas Fields, EPA, Research Triangle Park, N.C., July, 1976.

Characteristics, Requirements, and Impacts (continued)

Combustion Emissions and Controls. External combustion equipment is used for process heating and regeneration of chemical solutions in the sulfur recovery process. If natural gas is used as a boiler fuel, the major emissions released are nitrogen oxides (NO_x). Emission quantity will vary by the size and type of the equipment and the loading. Typical emission factors for industrial boilers are presented in Table 5.4. In addition, emissions from two boilers operating in existing gas plants are presented.

TABLE 5.4

EMISSIONS FROM INDUSTRIAL BOILERS FUELED BY NATURAL GAS

Type of Unit	(Typical Emissions) a		(Existing Boiler Emissions) b	
	Power Plant Boiler	Industrial Process Boiler	Boiler A (using 76,000 cu. ft./hour)	Boiler B (using 89,000 cu. ft./hour)
Pollutant	lb/10 ⁶ ft ³	lb/10 ⁶ ft ³	lb/10 ⁶ ft ³	lb/10 ⁶ ft ³
Particulates	5-15	5-15	4.9	4.84
Sulfur oxides	0.6	0.6	0.45	0.55
Carbon monoxide	17	17	16.9	16.5
Hydrocarbons (as CH ₄)	1	3	2.99	2.97
Nitrogen oxides	700	120-230	76.7	75.9

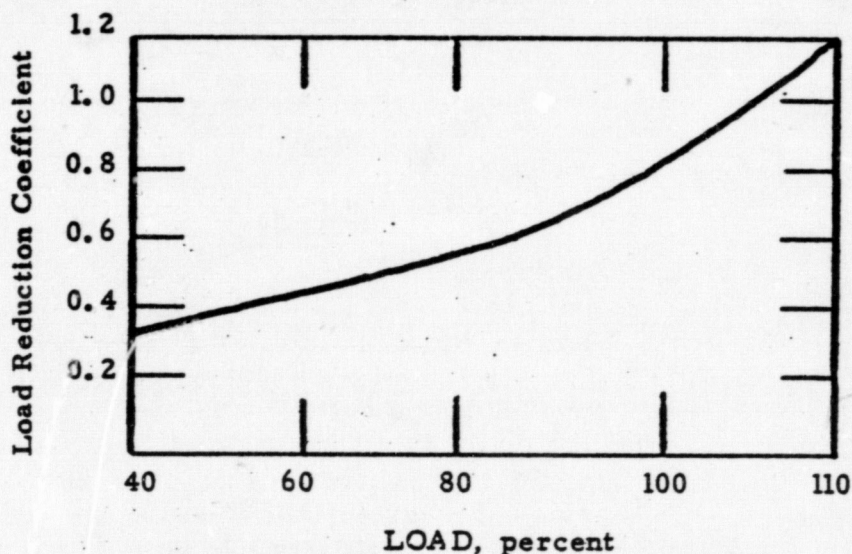
a. Compilation of Air Pollutant Emission Factors. 2nd ed., (1976) p. 1.4-2.

b. Prepared by NERBC staff based on information supplied by the Offshore Operators Committee.

For units generating more than 100 million BTU/hr., nitrogen oxide emissions will vary as the load on the boiler varies, decreasing with decreasing load. A coefficient has been determined which relates decreased loads to decreased emissions. These coefficients are presented graphically in Figure 5.4.

Characteristics, Requirements, and Impacts (continued)

FIGURE 5.4

LOAD REDUCTION COEFFICIENT AS FUNCTION
OF BOILER LOAD

Source: Compilation of Air Pollutant Emission Factors. 2nd edition, 1976, p. 1.4-2.

The coefficient for a particular load can be read off the graph and multiplied by the emissions at 100% load (from Table 5.4) to give the reduced load nitrogen oxide emissions. (For units of this size, power plant boiler factors are applicable.)

Example: A 120 million BTU/hr. boiler is operating at a 60% load. Nitrogen oxide emissions are:

$$700 \text{ lb./}10^6 \text{ ft.}^3 \times 0.42 = 294 \text{ lb./}10^6 \text{ ft.}^3$$

(from Table 4) (60% load reduction coefficient)

Particulate and nitrogen oxide emissions are currently regulated by federal standards. (There are no current standards on sulfur dioxide emissions for gas burning boilers.) Comparison of these standards with the emissions from the two previously mentioned boilers in operation are presented in Table 5.5.

Characteristics, Requirements, and Impacts (continued)

TABLE 5.5

EMISSIONS FROM INDUSTRIAL BOILERS
(lb/10⁶ BTU/hr.)

	<u>Federal Standard^a</u>	<u>Boiler A^b</u>	<u>Boiler B^b</u>
particulates	0.05	0.005	0.005
NO _x	0.1	0.08	0.08

Source: ^a40 CFR 60; 36 FR 24878, 12/23/71^bPrepared by NERBC based on information supplied by the Offshore Operators Committee.

Nitrogen oxide emissions can be lowered by using different methods of boiler operation, such as biased or staged firing. In biased firing, various mixtures of air and fuel are used in different burners. In staged firing, fuel-rich mixtures are first burned, followed by injection of air above the flame zone to complete the combustion process. These two processes can reduce nitrogen oxide emissions by 30 to 70 percent.¹²

Compressors are used in a gas processing plant to help move natural gas through distribution pipelines, and use natural gas as fuel. Sulfur oxides (SO_x) (if other than sweet gas is used), and hydrocarbons are the major emissions; emission factors are presented in Table 5.6.

TABLE 5.6

EMISSIONS FROM COMPRESSORS FUELED BY
NATURAL GAS

<u>Pollutant</u>	<u>lb/10⁶ft³</u>	<u>lb/hr</u>
Sulfur oxides	0.6	--
Hydrocarbons	1.2	4.2

Source: EPA, Compilation of Air Pollutant Emission Factors, 2nd edition, 1976, 0.3.3.2-1.

¹² Thomas Lahre, "Natural Gas Combustion", in EPA, Compilation of Air Pollutant Emissions Factors, 2nd Edition, 1976, 0.1.4.1-1.4.2

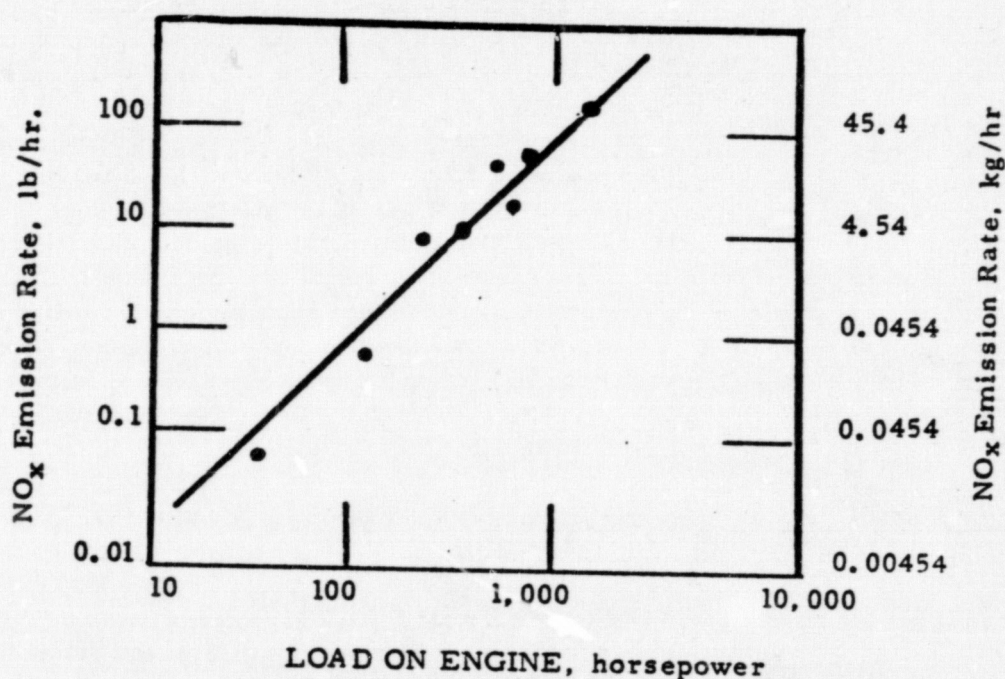
5.26

Characteristics, Requirements, and Impacts (continued)

Nitrogen oxide emissions are a direct function of the load on the compressor engine. This relationship is presented in Figure 5.5.

FIGURE 5.5

NITROGEN OXIDE EMISSIONS FROM COMPRESSOR
ENGINES



Source: Compilation of Air Pollutant Emission Factors, 2nd edition, 1976, p. 3.3.2-2.

Vehicle emissions from trucks used to remove products (sulfur and liquid hydrocarbons) from a gas plant, and from employee automobile traffic, can be expected to add primarily carbon monoxide, hydrocarbons, and nitrogen oxides to the air, both at the site and along nearby highways. Emissions from these vehicles must meet the current federal standards presented in Appendix C.

Sedimentation
and Runoff

Since the soil at the plant site will be reworked and compacted, its water retention properties will

Characteristics, Requirements, and Impacts (continued)

be altered. As a result, less water may seep through the soil to the ground water, and more may run off the site as surface water. To the extent that this reduces ground water aquifer replenishment, this can have consequences in regions where salt water intrusion is a potential problem.

Large quantities of oils and hazardous materials are stored at gas plants. These include sulfuric acid, lubricating oil, absorption oil, and sodium hydroxide. In addition, if gas plant products are not delivered by pipeline, storage facilities must be provided on the site for 3 to 5 days of production. Soil and vegetation in the vicinity of the plant may become contaminated with small amounts of these materials. Runoff water removes these contaminants from the soil and vegetation. This runoff will adversely affect the quality of the receiving water unless the receiving water is already highly polluted or the runoff water is collected and treated prior to discharge to the receiving waters.

Wastewater Effluents

Domestic Wastewater. Because of the small number of employees at the gas plant, only limited amounts of domestic wastewater may be disposed of in either a septic tank or an existing sewer system. No adverse environmental effects are anticipated from this source.

Cooling Water. Process cooling requirements can be accomplished by air, water, or a combination. Cooling water may represent up to 70-100% of the wastewater effluents from a gas plant. Where water is used, a "once through" system or a "closed cooling tower" system may be employed. "Once through" systems in which heated water is not reused, require the largest volumes of water. They also produce the most wastewater. Cooling systems in which the water is cooled so that it can be reused, require less water per unit of gas processed. Hence, they produce less effluent as well.

REFINERIES

There are about 140 refining companies operating 276 refineries today in the United States (including Puerto Rico and the Virgin Islands). Using both imported and domestic crude, the total refining capacity of these refineries is about 16.0 million barrels per day (bbls/day), slightly less than the 16.4 million bbls/day total domestic demand for petroleum products. Domestic refining capacity has been expanded significantly since 1970 -- 3.9 million barrels per day. However, most of this capacity increase has been through expansion of existing facilities; only 901,000 bbls/day of new capacity has come from the construction of new refineries.¹

In general, there is now no direct correlation between the discovery of commercial quantities of oil and gas in a frontier OCS area and construction of new refineries in adjacent states. This is particularly true if the frontier area is within reasonable distance of existing refineries with expansion capability in which imported crude can be replaced by OCS crude. However, in those areas possessing a substantial market for refined petroleum products and distant from existing refineries, the possibility of new refinery construction, whether by major or independent oil company, does exist.

DESCRIPTION OF FACILITY

The modern refinery consists of a series of units designed to produce a number of petroleum products by physically and chemically altering all or part of the crude oil stream. The complexity of this system depends on the type of crude oil being refined and the number and characteristics of the products desired.

¹ American Petroleum Institute, Petroleum Refining Data and Information Book.

6.2

Description of Facility (continued)

In addition to the processing units, other components of the refinery include storage tanks, influent and effluent water treatment facilities, ancillary buildings and services (administration building, machine shop, storage and warehouses, electrical substation, firehouse, pumping stations, truck loading terminals, etc.), transportation systems (roads, pipelines for crude supply and products outputs, railroad spurs, parking lots, etc.), and a buffer zone.²

Figure 6.1 shows the Mobil Oil Company's refinery at Joliet, Illinois, a typical modern refinery. The Joliet refinery, located 45 miles from Chicago, began full scale operation in 1973 and is considered by both industry and regulatory agencies as an example of the best technology for air and water pollution control.

The plant is a light fuels refinery with a capacity to refine 175,000 barrels of sour crude per day. The production of high octane gasoline is emphasized, but other products include home heating oil, jet fuel, petroleum coke, and liquified petroleum gas (LPG).

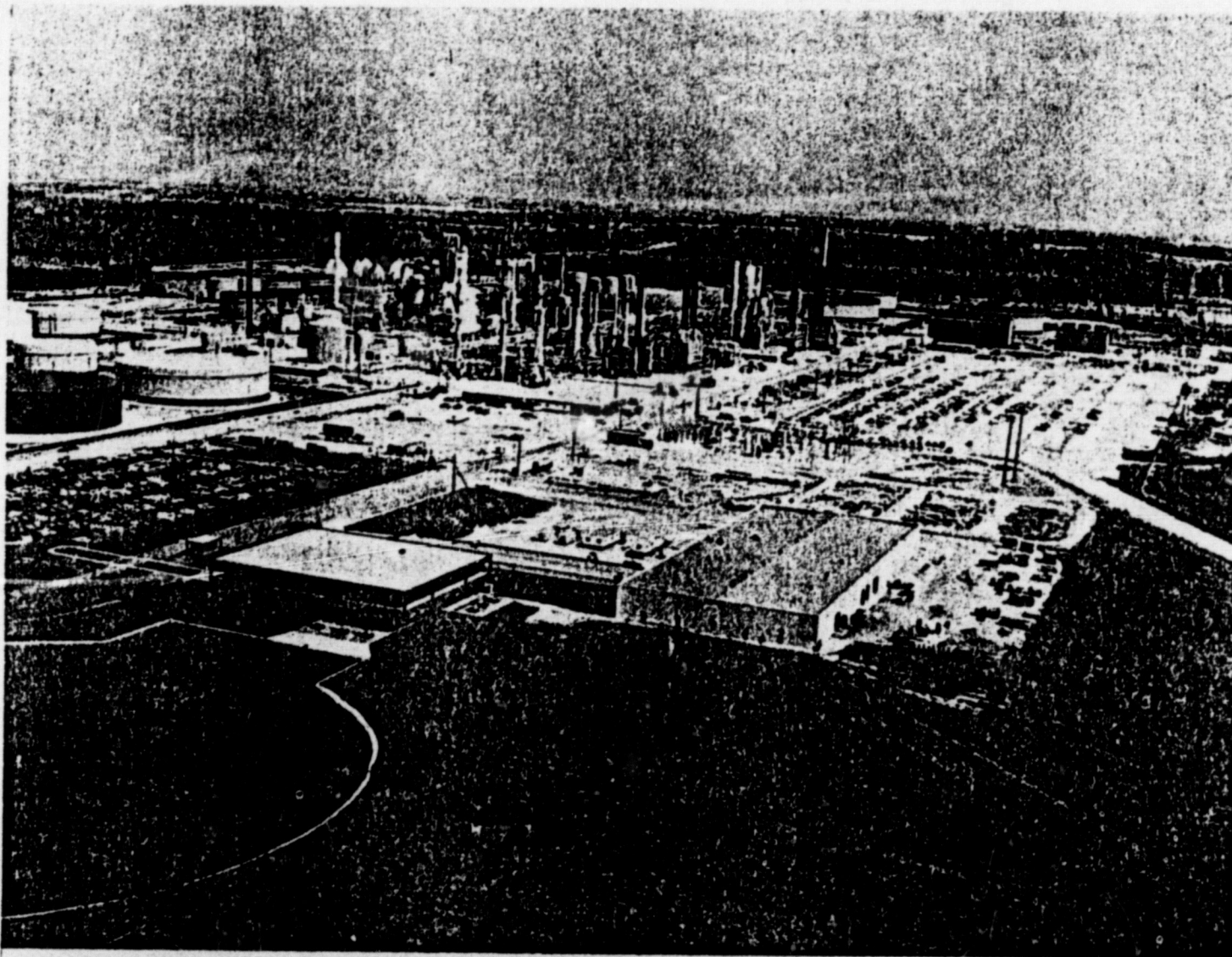
Processes employed at the refinery, and their capacities in barrels per day, include: two-stage crude distillation (175,000); fluid catalytic cracking (77,000); catalytic reforming (44,000); naptha hydrosulfurization (54,000); alkylation (18,000); and delayed coking (28,000). Two sulfur plants with a capacity of 150 tons per day, and saturate and unsaturate gas fractionation plants are also located at the refinery site. The coker produces about 1700 tons of coke per day.

The plant occupies a 1200 acre site, with 90 acres devoted to storage and 65 acres to processing. The refinery is served by three crude oil pipelines. Product is shipped either by barge (20 percent) from the refinery's wharf on the DesPlaines river, or by pipeline. Depth at the wharf is nine feet.

² "The Design and Construction of a Refinery," The Impacts of an Oil Refinery Located in Southern New Hampshire: A Preliminary Study, Chapter II, (University of New Hampshire, 1974), p. 11.

FIGURE 6.1

MOBILE OIL COMPANY REFINERY AT
JOLIET, ILLINOIS



6.3

Description of Facility (continued)

2857

Description of Facility (continued)

The refinery took 27 months to build, at an estimated cost of \$200 million, of which \$34 million was for pollution control equipment. At present the refinery operates at three shifts and employs a total of 545 workers. These personnel include 150 management employees, 370 laborers, and 25 clerical workers. The total annual payroll is \$10 million.

The Joliet plant uses 9.6 MGD of water, all of which is withdrawn from the DesPlaines River. All water in the plant, most of it for the plant's cooling towers, goes through a 14:1 recirculation rate. All wastewater receives treatment and is discharged to the DesPlaines River, at a rate of 3.3 MGD. The river is classified by the state as "restricted use: suitable for secondary contact and indigenous aquatic life".

Complete information on solid wastes is not available, though the plant does generate five tons per day of catalyst wastes and limes landfilled, and 1.5 tons per day of oiled sludges which are returned to the process for a net waste of zero.

The operation of the refinery requires an average of 800,000 KW per day of electricity (peaking at 930,000 KW/day); 800 barrels per day of low sulfur fuel oil; and 41 million cubic feet per day of gas, most of which is provided by the refining process itself. The refinery also uses 3700 barrels per day (fuel oil equivalent) of its own catalytic coke.³

A "new source" topping refinery has recently been proposed by the Pittston Oil Company, to be built on a 650 acre coastal site at Eastport, Maine (Fig. 6.2). If constructed, this refinery will be capable of processing 263,000 barrels of high sulfur content crude oil per day.

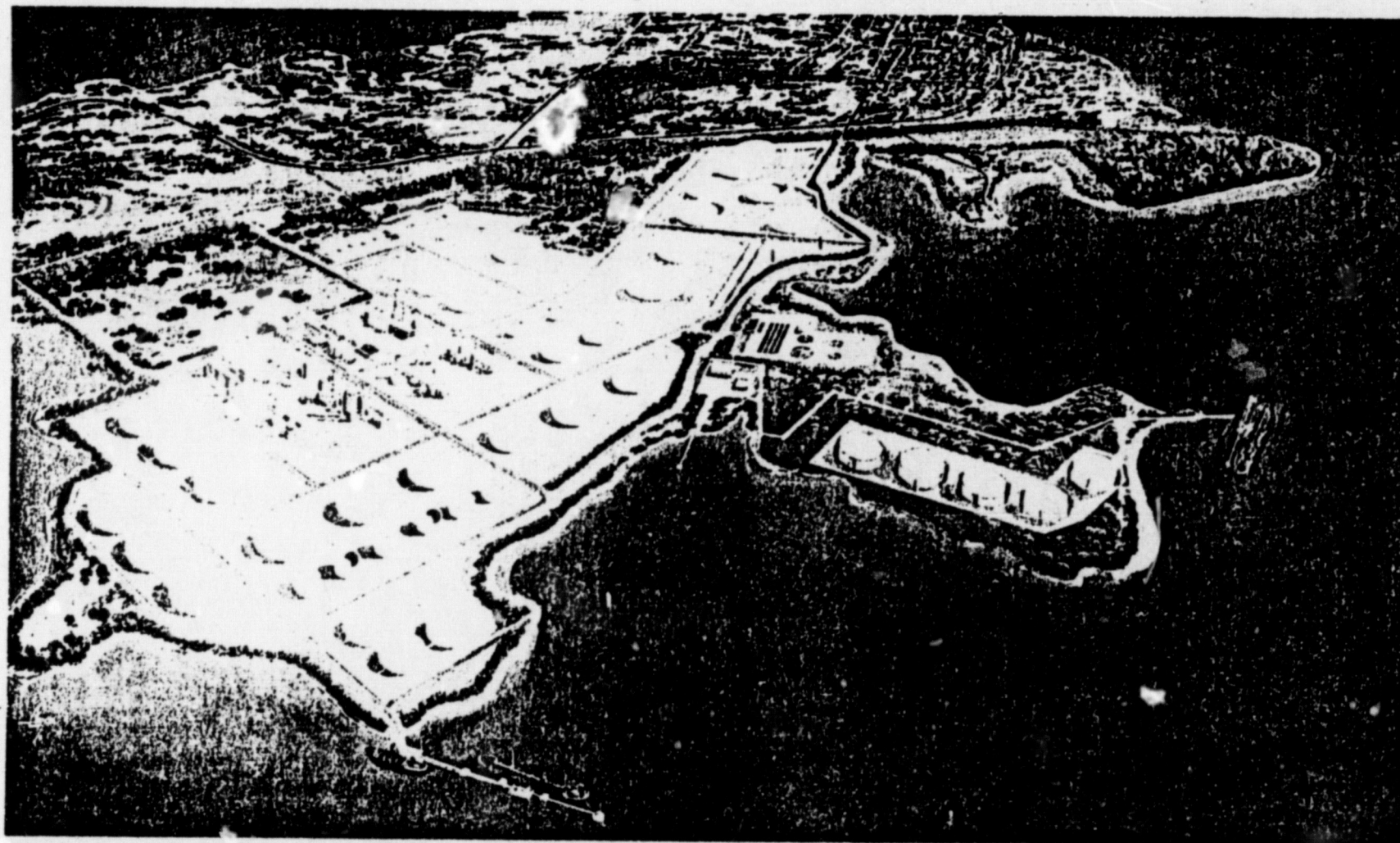
The principal products to be produced at the facility are: No. 5 industrial fuel oil (96,400 bbls/day); No. 2

³ The source for all information on the Joliet refinery is the Mobil Oil Manufacturing Division, New York.



SOU

FIGURE 6.2 ARTIST'S SKETCH OF PROPOSED 250,000 BPD PITTSTON OIL REFINERY
AT EASTPORT, MAINE



SOURCE: U.S., ENVIRONMENTAL PROTECTION AGENCY, "DRAFT ENVIRONMENTAL IMPACT
STATEMENT OF PITTSTON OIL REFINERY PROPOSAL FOR EASTPORT MAINE,"
(WASHINGTON, D.C.), pp. IV-219.

Description of Facility (continued)

heating oil (80,500 bbls/day; gasoline (49,600 bbls/day; and propane and butane (7,700 bbls/day). Approximately 450 tons of pure sulfur will also be produced daily. The storage capacity at the refinery will be 13.5 million barrels of oil and oil products and 5 million barrels of crude oil storage. The fuel oil and gas requirements for the facility are estimated at 13,500 bbls/day; the electric power requirement is projected at 60,000 kilowatts (KW).

Since Pittston Co. intends to employ closed-cycle cooling, it has not applied for a cooling water discharge permit. The Environmental Impact Statement indicates a total flow of 10.5 gallons/barrel of throughput for this class of refinery.) Pittston estimates a fresh water requirement of 2 million gallons per day (MGD). Flows of ballast water, process wastewater and contaminated runoff are estimated at 2.3, 0.86, and 0.43 MGD, respectively. The proposed discharge of wastewater will empty into coastal waters suitable for shellfish harvesting.

Tankers of 70,000 Dead Weight Tonnage (DWT) capacity for product shipment and 250,000 DWT capacity for delivery of crude oil are also proposed. The Pittston Company estimates that, by 1980, construction of a new 250,000 bbl/day refinery will cost at least \$500 million and directly employ as many as 2,275 construction workers, whose annual payroll will total between \$20 to \$30 million over a three year period. When the refinery is operating, about 300 people will be employed, with a total annual payroll of approximately \$3 million.⁴

The Refining Process

Refineries are highly automated facilities. Crude oil arrives at the facility by pipeline or tanker and is stored. When it enters the production stream, the crude may undergo as many as four distinct processes to produce the mix of products desired: separation, conversion, treatment, and blending. In separation, the crude oil is separated through distillation into light, intermediate,

⁴U.S., EPA, Draft Environmental Impact Statement of Pittston Oil Refinery Proposal for Eastport, Maine, (Washington, D.C.), pp. 199-289.

seek large sites which permit both expansion and a substantial buffer zone.

Modern refineries have been designed to reduce water usage through air cooling and recirculating systems with cooling towers. However, the increased equipment and power requirements associated with closed cooling water systems often make this choice uneconomical. Refiners will still seek large parcels of land with abundant water supplies. Because of the economic advantages of using large tanker for transporting crude oil coastal sites adjacent to deep water are often preferred.

Specific environmental regulations, and the extent of their enforcement, can influence industry site selection. The importance of these regulations for site selection varies according to company policy, as well as to the timing and manner in which environmental regulations are enforced. The focus of pollution control is also important. The refinery industry has the ability to meet various pollution control standards, but in areas where air quality is of primary concern, air emissions from refineries are low, but the quality of water effluent is poor. The reverse is often true in areas where the emphasis is on water quality.

Air Quality Limitations

The new source air pollution control strategy can have a significant effect on the number of potential refinery sites. Approval or denial of a permit for a new source will be determined by the degree to which the refinery will interfere with the attainment of National Ambient Air Quality Standards in the region. This suggests that it may be extremely difficult to obtain permit approval for a new refinery in an air quality control region where standards are barely being met, or are already exceeded. The same holds true in clean areas, where significant degradation of air quality can be expected, even though air quality standards may be met. This is especially true in areas where there are no major emissions, precluding the "emission trade off" concept for new sources in non-attainment areas.

¹⁰ G. Kerlin and D. Rabovsky, Cracking Down: Oil Refining and Pollution Control, Council on Economic Priorities, 1975, (New York), pp. 41-60.

Public Opinion
and Environmental
Sensitivity

Of all the facilities associated with OCS oil and gas development, oil refineries are the most controversial. Recent experience indicates that refiners will avoid areas having a history of determined opposition to major new industrial development, rather than attempt to persuade local officials and the public that a refinery be sited in their community.

For roughly the same reasons, refiners will, whenever possible, avoid areas classified as "environmentally sensitive." The oil companies can meet current environmental standards and, apart from air quality limitations, pollution control regulations do not appear to be a limiting factor in refinery siting decisions. Nevertheless, largely because of the time and costs involved in litigation, refiners will seek areas with low environmental sensitivity for future proposals.

State Taxes

The climate toward business in general, and state taxes on major industrial facilities in particular, can play a major role in the final siting decision. It is not uncommon for oil to be brought ashore in one state and refined in another, where the tax situation is more favorable.

CHARACTERISTICS,
REQUIREMENTS,
AND IMPACTS

The characteristics, requirements, and impacts examined in this section relate to a moderately complex 250,000 barrels per day refinery. The summary table at the end of this chapter displays similar information for refineries in both the 250,000 and 500,000 bbls/day range, producing either a low or high fuels mix.

Land
Requirements

To a degree, the land required for a refinery depends on the throughput of the facility and the complexity of the product mix. However, there is no absolute relationship between size, complexity and land use.

A new domestic refinery in the 250,000 bbl/day range is likely to require on the order of 1,000 to 1,500 acres of clear, flat, industrially zoned land.

Characteristics, Requirements, and Impacts (continued)

Land Use Patterns. Of the total land required, roughly 200 acres will be required to accommodate the processing units, 400 acres for buildings and storage, and the remainder for buffer. The land acquired is likely to be more than what is initially needed, since it is cheaper to expand existing facilities later than to build a new refinery. Although these facts are difficult to extrapolate, one study estimates that approximately 175 acres would be required for each 10,000 bbls/day of new refinery capacity: 22 acres for buildings and processing units, 13 acres for buffer and 140 acres for further expansion.¹¹

Soil and Slope Requirements. The site should have a maximum slope of 5°, moderately well-drained soil, and be capable of supporting large storage tanks and processing units.

Special
Locational
Requirements

The industry prefers a site close to, but not actually in, a major urban area (where congestion might restrict expansion). Since large quantities of petroleum and materials will be received and shipped from the site, access to railhead, well-maintained highways, port facilities, and crude and product pipelines are additional special locational requirements. The availability of related industries, such as machine shops, valve manufacturers, warehousing, and contract maintenance companies, is also ideal.

Water
Requirements

Refineries can be major users of water. Water use depends upon the size of the refinery, the complexity of the product mix, the processing and cooling system technology, and water quality.¹²

¹¹Sullom Voe District Plan.

¹²F. R. Hall, "Water Requirements and Possible Source of Supply," Impact on New Hampshire, Chapter 6, p. 7.

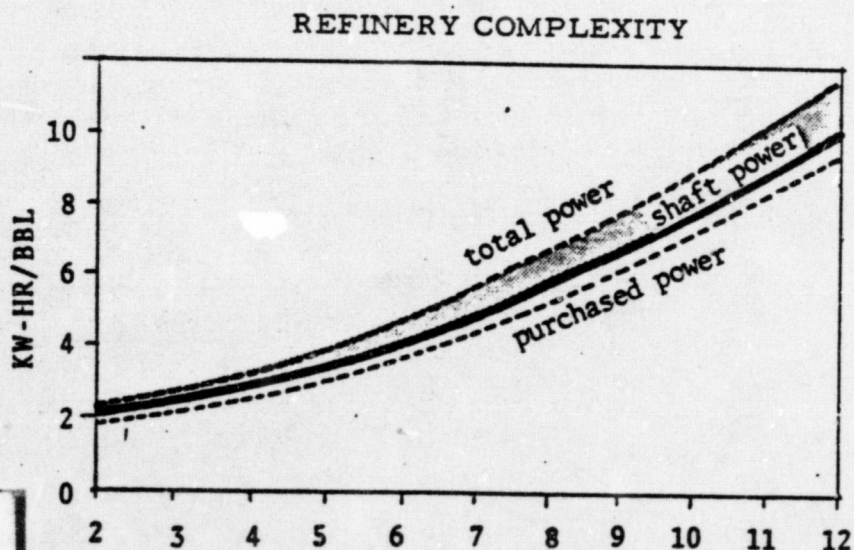
With an efficient mix of air and water cooling, a 250,000 bbl/day topping and cracking refinery would use from 5 to 15 million gallons of water/day (consuming 5 mgd through evaporation). This water requirement could be minimized by additional use of air cooling and a closed water system. However, this method is impractical on a large scale, since it is much more expensive and requires a tremendous amount of power not normally considered by the industry. Freshwater needs could also be reduced by using brackish water or saltwater for cooling as occurs in newer refineries located along the seacoast.

Energy Requirements

Electricity, fuel oil and gas are used for power in refineries. Typically, purchased electricity provides nearly 90 percent of the refineries power -- a per barrel use of 2 kwh for a simple refinery and a 9 kwh for a complex refinery, as illustrated in Figure 6.3.¹³ A complex 250,000 bbls/day refinery has a total electrical energy demand of about 100,000 kw.

The same refinery may also require between 15,000 - 25,000 bbls/day of low sulfur fuel oil or fuel gas to generate electricity and steam required to power machinery.

FIGURE 6. 3



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Source: Oil and Gas Journal

¹³ W. L. Nelson, "Unit Utility Requirements." Oil and Gas Journal. June 14, 1976.

Characteristics, Requirements, and Impacts (continued)

Noise levels during the construction phase will also be elevated around the site. Actual increases will depend on the type and extent of alteration and the numbers and types of equipment necessary. For example, if piling placement is necessary, noise levels could increase to 95 to 105 decibels at the site. Even in an area where ambient levels are high (70 decibels), this level of noise could be perceived up to 0.3 miles from the source. Other sources of noise include heavy machinery, such as pumps, compressors, cranes and equipment.

Solid waste generated during this period will consist primarily of packaging materials, timber or scrap metal, which can be either sold for reuse, or disposed of on the site, in a nearby incinerator or landfill. Smaller quantities of hazardous wastes (e.g. debris and packaging material contaminated with spilled fuels, solvents, and paints) are produced and must be disposed of in a manner which prevents contamination of air, groundwater, or surface water.

Although this discussion has covered some of the major impacts expected from site alteration and construction of a refinery, the actual overall impact anticipated would have to be determined on a site specific basis.

Air emissions

The magnitude of emissions to the atmosphere and all other environmental impacts from the operation of an oil refinery will depend upon the amount of throughput, the chemical characteristics of the crude oil stream, plant complexity, plant design, the pollution control equipment installed, and the emission standards.

Major sources of air emissions at refineries include:

- processing from sources such as cracking and coking units;
- process machinery such as boilers and compressors;
- leaks from valves and seals and floating roof tanks; and
- mobile source emissions.

Although the volume of emissions will remain relatively constant, local ambient air quality may be considered in choosing a site. In regions where ambient concentrations approach maximum federally allowable concentrations, emissions from a refinery may limit the ability of a region to reach or maintain these standards. In a non-industrial region, where concentrations of regulated pollutants are low, it is unlikely that emissions volumes will be sufficient to increase ambient concentrations beyond federally acceptable levels, although the site could be located within a non-industrial region where a state has restricted further degradation.

Table 6.2 summarizes major air emissions generated by the operation of an oil refinery. Table 6.3 presents controls available for limiting the emissions of major types of pollutants.

Processing Emissions. One of the major steps in the processing of petroleum is catalytic cracking, the alteration of the molecular structure of hydrocarbons by heat and catalytic conversion. The major emissions associated with catalytic cracking include carbon monoxide, sulfur oxides, hydrocarbons, and particulates. The volume of emissions will vary depending on the throughput of the cracking unit and the extent to which controls are used. Average emissions from two types of units are presented in Table 6.2.

Spent catalysts from this cracking process are regenerated by passing through a vessel in which coke is burned off. The major emission from these regenerators is particulate matter that can be controlled by electrostatic precipitators. Average uncontrolled emissions from a cracking unit are 242 pounds of particulates per 1000 barrels of fresh feed.

Coking is a decarbonization process which results in the production of a calcined coke with a carbon hydrogen ratio of 1,000 and higher. Through this process, the yield of residual fuel oil from crude oil is reduced in favor of an increase in the yield of distillate fuel oils. Average uncontrolled emissions from a fluid coking unit are 523 pounds

6.29

Characteristics, Requirements, and Impacts (continued)

Runoff from storage and process areas of a refinery could be collected and stored. The runoff from the process area is treated and discharged with the process water. According to existing effluent limitations (40 CFR 419) storm water runoff from the storage areas may not exceed a concentration of 35 parts per million of total organic carbon or 15 parts per million of oil and grease when discharged.

During periods of heavy rain, large volumes of runoff water must be held before treatment and discharge. In order to prevent overloading and disruption of treatment facilities, the storm runoff is retained in holding ponds or tankage until it can be handled by the treatment facility. If processing facilities are present at the refinery, contaminated runoff must be treated at the main treatment plant to achieve the effluent limitations which are presented in Table 6.5.

TABLE 6.5
EFFLUENT LIMITATIONS FOR STORM-
WATER RUNOFF UNDER STANDARDS OF
PERFORMANCE FOR NEW SOURCES

Characteristic	Maximum for any one day	Average daily values for 30 consecutive days shall not exceed
Biological oxygen demand (5 day test)	0.400 (lb/M gal of flow)	0.210
Total suspended solids	0.26	0.170
Chemical oxygen demand	3.100	1.600
Oil and grease	0.126	0.067
pH	within range of 6.0 - 9.0	

Source: 10 CFR 419.15 40: 419.15 (3)c(1)
1975, p. 749.

Even after treatment, stormwater runoff from a refinery will tend to increase contaminant levels of receiving waters.

Wastewater

Refinery effluent wastewater includes:

- cooling water;
- process water;
- boiler blowdown water; and
- sanitary wastes.

The quality and volume of wastewater discharged, and the resultant environmental impacts from the operation of an oil refinery, will depend upon the physical and chemical characteristics of the crude oil and refined products, the amount of throughput, the plant complexity and design, and the sensitivity of biota in the receiving waters. Discharge contaminants may be reduced by the installation of appropriate pollution control equipment and by strict environmental regulations.

Cooling Water. Cooling water represents a significant proportion of the wastewater effluent from an oil refinery. Oil refineries may use a "once through" cooling system, a cooling tower, or a combination of these methods. "Once through" systems, in which the heated water is not reused, require the largest volumes of water and, hence, produce the most wastewater. Recycle cooling systems (cooling towers), in which the water is cooled so that it can be reused, require less fresh water per unit of oil processed. As a consequence they produce less effluent, as well. There are various types of cooling towers, including evapoative cooling systems, dry cooling systems, and wet-dry systems.

The quantity of water required for a recycle cooling system depends upon the quality of the water which is being used. Very clean intake water can be recycled through a cooling tower up to five times or more before it must be discharged. Since each passage through the cooling tower

6.31

Characteristics, Requirements, and Impacts (continued)

results in evaporation, any dissolved or suspended particles will be present in increasing concentration with each reuse of water.

Substances concentrated in the blowdown and heat added during the condenser cooling operation could produce serious impacts on the receiving waters. Chemicals added to the cooling water stream to reduce corrosion and fouling within the tower and the condenser system (including chromium and chlorine) may be extremely toxic to aquatic organisms. The chemicals used and the concentrations maintained in the cooling system are shown in Table 6.6.

TABLE 6.6
CHEMICALS ADDED
TO COOLING WATER

<u>Chemical</u>	<u>Concentration Maintained</u>
Sulfuric Acid	(enough to maintain) pH approx. 7
Chromate	30.0 ppm (5-20)*
Zinc	3.0 ppm (1-4)*
Chlorine	0.1 - 0.2 ppm

* Gulf Oil Company, Philadelphia, Pa.

Source: Testimony of F.W. Wheeler for the Texas Oil and Gas Association, 8/17/73.

The presence of these substances could further increase the adverse impacts of the heated discharge on the receiving water. Maximum effluent discharges of these substances are regulated through implementation of the discharge limits established by the NPDES.

Federal regulations also control the thermal discharges from oil refineries. The plant operator may be permitted to exceed these standards, however, if he can demonstrate that the proposed heat discharge does not result in appreciable harm to the organisms in or on receiving waters.

Since organisms can be killed by impingement on the cooling water intake screens. By passage through the cooling water system, or in the receiving water, very specific federal requirements are imposed on the size of the mixing zone, volume of cooling water, the temperature of the discharge, and the location and design of the intake and discharge structures. These measures are taken to ensure the maintenance of a balanced indigenous population of fish, shellfish, and wildlife in or on the surface waters surrounding the plant.

Evaporative emissions from cooling towers can also cause environmental impacts. These emissions (primarily water vapor) can produce unfavorable meteorological conditions (such as fog and icing) in the vicinity of, and downwind from, the plant. If salt water is used in the cooling towers, precipitating salt crystals will have additional adverse impacts on the surrounding biota.

Cooling water, although considered to be "not oily", actually comes in contact with oil due to leaks in heat exchangers. Only cooling water with a total organic carbon increment of less than five parts per million can be discharged.¹⁹ A considerable volume of water (estimated at over 40 percent of the water utilized in the plant) is removed through evaporative cooling processes. Care must be taken to prevent the salt wedge from penetrating further inland as a result of this water withdrawal. Changes in the spatial and vertical salinity profiles in estuaries can have a considerable impact on the organisms which inhabit these estuaries for some stage of their life cycle. Evaporation of cooling water also results in emissions of hydrocarbons to the atmosphere.

Process Water. Although it does not constitute the greatest volume of water used in refinery operations, process water may be the most contaminated. The processing pollutants are added during crude oil desalting, steam distillation, steam stripping, water washing of chemicals following treatment, catalyst regeneration, partial pressure reduction with dilution stream, treatment of water (e.g., nitrate addition for caustic

¹⁹ 40 CFR 21949, May 20, 1975.

Characteristics, Requirements, and Impacts (continued)

embrittlement control), transferring and storing oil, and vessel cleaning operations.²⁰

Some of the constituents of refinery wastewater and their concentrations are listed in Table 6.7. The upper limits for chemicals presented in this table would not be allowed under an NPDES permit.

TABLE 6.7
UNDESIRABLE COMPONENTS OF REFINERY WASTEWATER

<u>Pollutant</u>	<u>Concentration, ppm</u>
Floating and dissolved oil	1- 1,000
Suspended solids	--
Dissolved solids	0-5,000
Phenol and other dissolved organics	0-1,000
Cyanide	0-20
Chromate	0-60
Organic Nitrogen	0-50
Phosphate	0-60
Sulfides and Mercaptans	0-100
Caustics and acids	2-11 pH
	--

SOURCE: U.S., EPA, PB 238-096, Control of Oil and Other Hazardous Substances, (1974), p. 7-3.

Factors Affecting Pollutant Volume and Concentration.

The volume of process water derived from the refining of crude oil has been found to vary with the size and complexity of processing at the refinery. Large, complex refineries have a higher flow per unit of production than simple ones.²¹

²⁰ U.S., EPA, PB 238-096, Control of Oil and Other Hazardous Substances, prepared by S.K. Mencher, (1974), p. 8-2.

²¹ F.R. Hall, "Water Requirements," Impact on New Hampshire, Chapter VI.

Characteristics, Requirements, and Impacts (continued)

The concentration of pollutants in the effluent will also vary as a function of the complexity of the refinery's processing range from simple crude oil separation by distillation to more complex alterations involving rearrangement of chemical structures. In order to characterize median raw waste loads, the EPA has separated the Petroleum Refinery Industry into several categories. (Table 6.8.)

Data on raw waste loads from these subcategories are presented in Table 6.9. For comparison, average municipal wastewater loads are also presented.

It is evident from analysis to date that tremendous variability occurs in plant discharge concentrations and that the simpler refineries (topping) contribute smaller pollution loads than do the more complex refineries. For example, a refinery producing only fuel oil would produce smaller volumes of less polluted water than a refinery producing large proportions of gasoline.

The composition of crude oil being processed may also affect effluent quality. When heavier crude oil is refined, chemical oxygen demand (COD) concentrations are higher than when refining lighter crude oils. There appears to be no meaningful correlation between feedstock and raw waste load for Biological Oxygen Demand (BOD), total suspended solids, oil and grease, phenol and ammonia.²²

(Discharges from specific refinery processes will be discussed at a future date.)

Boiler Water. Water used in steam generation at a refinery is initially preconditioned to remove suspended solids and hardness, and may even be deionized before entering boilers. The specific chemicals added to boiler water to minimize corrosion, sludge, and scale are shown in Table 6.10. Biocides and oxidizing agents are also added.

²² 40 CFR 98 Tuesday, May 20, 1975, p. 21944.

TABLE 6.8

**SUBCATEGORIZATION OF THE PETROLEUM REFINING INDUSTRY
REFLECTING SIGNIFICANT DIFFERENCES IN WASTEWATER CHARACTERISTICS**

<u>Subcategory</u>	<u>Basic Refinery Operations Included</u>
Topping	Topping and catalytic reforming whether or not the facility includes any other process in addition to topping and catalytic process. This subcategory is not applicable to facilities which include thermal processes (coking, visbreaking, etc.) or catalytic cracking.
Cracking	Topping and cracking, whether or not the facility includes any processes in addition to topping and cracking, unless specified in one of the subcategories listed below.
Petrochemical	Topping, cracking and petrochemical operations, whether or not the facility includes any process in addition to topping, cracking and petrochemical operations, * except lube oil manufacturing operations.
Lube	Topping, cracking and lube oil manufacturing processes, whether or not the facility includes any process in addition to topping, cracking and lube oil manufacturing processes, except petrochemical operations. *
Integrated	Topping, cracking, lube oil manufacturing processes, and petrochemical operations, whether or not the facility includes any processes in addition to topping, cracking, lube oil manufacturing processes and petrochemical operations. *

*The term "petrochemical operations" shall mean the production of second generation petrochemicals (i.e., alcohols, ketones, cumene, styrene, etc.) or first generation petrochemicals and isomerization products (i.e., BTX, olefins, cyclohexane, etc.) when 15 percent or more of refinery production is as first generation petrochemicals and isomerization products.

Source: U.S., EPA, PB 238-612, Development Document for Effluent Limitations; Guidelines for New Source Performance Standards for the Petroleum Refining Point Source Category, prepared by M. Halper, (1974), p. 60.

TABLE 6.9

TYPICAL RAW WASTE LOAD FOR PETROLEUM REFINERY
SUBCATEGORIES AND SELECTED MUNICIPAL WASTEWATERS (mg/l)

Pollutant Parameter	Top- ping	Crack- ing	Petro- chemical	Lube	Integrated	Muni- cipal System	Median Range from all Refinery Data
Biological Oxygen Demand (5 day)	10-50	30-600	50-800	100-700	100-800	100-300	
Chemical Oxygen Demand	50-150	150-410	300-600	400-700	300-600	200-400	
Total Organic Carbon	10-50	50-500	100-250	100-400	50-500	50-250	
Total Suspended Solids	10-40	10-100	50-200	80-300	20-200	100-300	
Oil and Grease	10-50	15-300	20-250	40-400	20-500	-	
Ammonia- Nitrogen	.05-20	0.5-200	4-300	1-120	1-250	-	
Phenols	0-200	0-100	0.5-50	0.1-25	0.5-50	-	
Sulfides	0-5	0-400	0-200	0-40	0-60		
Total Chromium	0-3	0-6	0-5	0-2	0-2		
Zinc							0.4-1.84
Total Dissolved Solids							400-700
Cyanide							0.0-0.18
Chloride							57-712
Phosphate-Phosphorus Phosphorus							0.096-9.49

* mg/l = parts per million (ppm)

Source: U.S., EPA, PB 238-612, Development Documents for Effluent Limitations Guidelines and New Source Performance Standards for the Petroleum Refining Point Source Category, prepared by M. Halper, (1974), pp. 74-90.

TABLE 6.10

CHEMICALS ADDED TO BOILER WATER TO REDUCE CORROSION, SCALE, AND SLUDGE

<u>Chemical</u>	<u>Concentration Maintained</u>
Phosphate	20-60 ppm
Bases enough to maintain	pH 10.2 - 10.6
Sulfite ^a	20 ppm
Sludge conditioners ^b	20 ppm
^a to reduce dissolved oxygen	
^b e.g., tannins, lignins, starch organics	

Source: Testimony of F. W. Wheeler for Texas Oil and Gas Association, 8/17/73.

The biocides and heavy metals such as chromate and zinc are toxic to some aquatic organisms. Sublethal physiological responses may also result. Detailed information on heavy metal and chlorine pollution may be found in Appendix A, Table 4.

Major sources of process wastewater at a refinery are summarized in Table 6.11.

Wastewater from a refinery is commonly discharged to surface waters after treatment. Although the degree of environmental damage, if any, will be related directly to the toxic nature of the discharge, and the biota present in the receiving waters, certain characteristics of the discharge zone are important. These include: the size of the effective mixing zone (dilution factor) or the ratio of discharge volume to receiving volume; the flushing rate or residence time, (estuaries characteristically have a slow flushing rate); and the physical-chemical characteristics of the receiving waters, e.g., marine water have a higher buffering capacity than fresh or estuarine waters.

Dose-effect relationships of contaminants found in cooling and process water discharges are summarized in Appendix A.

TABLE 6.11
REFINERY WASTEWATER SOURCES

<u>Source</u>	<u>Flow, GPM</u>	<u>% of Total</u>	<u>Source of Contamination</u>
Cooling Water	100-6,000	40-80 (<40) ²	Process leaks, treating chemicals and concentration
Water Softener & Boiler Blowdown	5-300	<10	Treatment and concentration
Refinery Processes ¹	20-1,200	20 (50)	Direct contact with oil and treating chemicals

¹ Crude oil desalting, overhead oily waste from units such as distillation, cracking, alkylation, treating, etc.

² Gulf Oil Co., Phila., Pa.

Source: U.S., EPA, PB 238-096, Control of Oil and Other Hazardous Substances, (1974), p. 7-2.

The Mobil Oil Company recently upgraded wastewater treatment facilities at their Paulsboro, New Jersey refinery in order to:

- reduce the volume of wastewater and its contaminants;
- retain contaminated storm water and wastewater flows which exceed treatment system capacity;
- combine their effluent discharges; and,
- treat their effluents to meet state and federal discharge regulations.²³

²³ Mobile Oil Manufacturing Division, New York.

Characteristics, Requirements, and Impacts (continued)

The new wastewater treatment facilities were constructed at a cost of \$25 million and went on line January 15, 1976.

One of the significant features of the Paulsboro wastewater treatment facility is its size: 800,000 square feet (20 acres). The facility includes:

- A Retention Basin - 7.5 million gallons
- API Separators
- Dissolved Air Flotation Units
- Two sets of Aeration Basins and Clarifiers
- Sand Filtration Units
- Chlorination Unit

The retention basin is only used for wastewater retention when there is a breakdown in the wastewater treatment system or when wastewater flows exceed the treatment capacity. When the treatment system can accommodate the stored wastewater, the water-oil mixture is pumped to the API Separator and then to the Dissolved Air Flotation Unit for initial gravity separation. Wastewater from the Dissolved Air Flotation Unit flows to the Biological Treatment Plant for further treatment in the Aeration Basins and the Clarifiers where an activated sludge process is used to further remove contaminants from the wastewater.

Final wastewater treatment involves disinfection with chlorine prior to discharge into the Delaware River.

Regulations and Controls. All new refineries are required to apply for a National Pollutant Discharge Elimination System (NPDES) Permit, under section 402 of the Federal Water Pollution Control Act of 1972. Although regulation of NPDES Permits has, in some instances, been delegated to individual states, it is EPA which actually classifies the proposed refinery according to "New Source" standards, (e.g., type of refinery, volume of crude oil refined). The permit calls for compliance to both EPA and state standards.

Characteristics, Requirements, and Impacts (continued)

Table 6.12 describes the effluent discharges which would be permitted on a daily maximum and 30 day average basis for a 250,000 bbl/day refinery. By 1983, refineries will have to meet best available control technology standards. Sample pollutant loadings under these standards are found in Table 6.13.

TABLE 6.12
PROCESS WATER EFFLUENT - NEW SOURCE STANDARDS
(lbs/day)

Fuel Mix	Low		High	
	Daily max.	30 day avg.	Daily max.	30 day avg.
BOD (5 day test)	1,675	900	1,175	655
Total Suspended Solids	1,000	575	725	410
COD	12,000	6,075	8,475	4,300
Oil & Grease	500	270	348	190
Phenol	12.3	5.75	8.5 ^a	4.0
Ammonia (as N)	1,900	875	1,350	613
Sulfide	10.8	5.0	7.5	3.5
Total Chromium	24.3	14.3	17.3	10
Hexavalent Chromium	5.25	2.35	3.75	1.65
pH	6.0-9.0	6.0-9.0	6.0-9.0	6.0-9.0

Source: Modular Results, "Petroleum Development in New England," Vol. II, (Arthur D. Little, Inc.), p. II-37.

TABLE 6.13
PROCESS WATER EFFLUENT-BEST AVAILABLE
TECHNOLOGY
(lbs/day)

Fuel Mix	Low		High	
	Daily max.	30 day avg.	Daily max.	30 day avg.
BOD 5	348	285	245	203
Total Suspended Solids	348	285	245	203
COD	1,975	1,550	1,400	1,100
Oil & Grease	70	55	50	40
Phenol	1.6	1.13	1.13	.80
Ammonia (as N)	463	348	328	245
Sulfide	7.5	5.0	5.3	3.5
Total Chromium	16.8	14.3	11.8	10
Hexavalent Chromium	.38	0.23	0.28	0.16
PH	6.0-9.0	6.0-9.0	6.0-9.0	6.0-9.0

Source: Modular Results, "Petroleum Development in New England," Vol. II, (Arthur D. Little, Inc.), p. II-37.

The Environmental Protection Agency recommends reducing process wastewater by segregating clean waters (non-contaminated storm water and cooling water) from process water. Separate effluent limitation guidelines have been established for each type of water discharge. Control technologies to reduce wastewater discharges are included in Table 6.14.

TABLE 6.14

CONTROL TECHNOLOGIES TO REDUCE REFINERY
WASTEWATER FLOWS

- 1) Use of air cooling equipment.
- 2) Reuse of sour water stripper bottoms in crude desalters.
- 3) Reuse of once-through cooling water as make-up to the water treatment plant.
- 4) Using wastewater treatment plant effluent as cooling water, scrubber water, and influent to the water treatment plant.
- 5) Reuse of boiler condensate as boiler feedwater.
- 6) Recycle of water from coking operations.
- 7) Recycle of waste acids from alkylation units.
- 8) Recycle of overhead water in water washes.
- 9) Reuse overhead accumulator water in desalters.
- 10) Use of closed compressor and pump cooling water system.
- 11) Reuse of heated water from the vacuum overhead condensers to heat the crude. This reduces the amount of cooling water needed.
- 12) Use of rain runoff as cooling tower make-up or water treatment plant feed.

Characteristics, Requirements, and Impacts (continued)

- 13) Maximum reuse of treatment plant effluent, evaporation and consumptive use.
- 14) Lime and lime soda softening to reduce hardness to allow further recycling.
- 15) Use of specially designed high dissolved solids cooling towers which would use the blowdown from other cooling towers as makeup water.

Source: U.S., EPA, PB 720,612, Development - etc., prepared by M. Halper, (May 29, 1975), p. 169 and 40 CFR 419, 40 FR 21944.

The final effluent limitations for petroleum refineries may require the addition of a final polishing step that could include solid removal through micro-straining, coagulation-flocculation, land disposal, granular media filters, intermittent sand filtration or chemical control. Materials in the effluent resistant to biological degradation are adsorbed fairly easily on activated carbon. However, the effectiveness of activated carbon has been rejected in a Federal Court.²⁴ In order to improve the quality of the effluent, the EPA recommends biological treatment to remove Biological Oxygen Demand before treatment with activated carbon.

Domestic Wastewater. Sewage from the refinery will be collected and delivered to a municipal treatment plant, or will receive secondary treatment in an on-site package treatment plant that includes chlorination before discharge to the receiving waters. Should these receiving waters also contain high organic carbon concentrations, organic chlorine compounds (e.g., chloroform, chloramines) which are highly toxic to certain aquatic organisms will be produced. Discharge of properly treated sewage wastewater into urban harbors is not expected to measurably degrade the receiving waters.

²⁴ Mobil Oil Manufacturing Division.

*Characteristics, Requirements, and Impacts (continued)*Noise Impacts

Noise impacts from refineries are derived from the operation of air fan coolers, blowers, compressors, cooling towers, motors, furnaces, gas engines, steam boilers, turbines, vents and other equipment. Noise levels and available controls are presented in Table 6.15.

TABLE 6.15
SOURCES OF NOISE AT AN OIL REFINERY

Source	Decibel level at operator's position	Control technology
Compressor	98	Muffler, enclosure of equipment
Furnace	97	Enclosure of equipment
Boiler	90 at 6 feet	Muffler
Blowers	79-100	Enclosure, design alterations
Cracking unit	80	(Not available)
Air fan cooler	79	Silencers, design alterations

SOURCE: U.S. EPA, Office of Noise Abatement and Control, Noise from Industrial Plants, prepared by L. S. Goodfriend Associates, (1971).

Actual noise levels will vary with the size of the plant, plant design and plant location. Meteorological conditions will also influence the noise levels. A modern refinery using the best available technology should be able to keep noise at about 50 decibels or lower at its boundary.²⁵ A minimum level of 55 decibels has also been suggested.²⁶

The most disruptive noise impacts of refinery operations are those intermittent noises, above the average background level, caused by flaring, pressure relief valves, and other equipment. These noises may, from time to time, be audible to the neighboring population.

²⁵ Impacts of an Oil Refinery Located in Southeastern New Hampshire, Chapter 3 (UNH, 1974), p. 19.

²⁶ Gulf Oil Co., Philadelphia, Pa.

Characteristics, Requirements, and Impacts (continued)

The primary mitigating tool for noise pollution is distance. An adequate buffer area around the plant may significantly decrease noise from the facility.

Solid Waste

Much of the solid waste generated by a refinery will, to some degree, be contaminated with oil and hazardous substances which require special handling and disposal. The type and quantity of solid waste produced depends on the volume and characteristics of the crude oil and the refining and treatment procedures employed. Some of the major solid wastes and their sources and characteristics are listed in Table 6.16.

Solid wastes are produced in the refinery from:

- oil storage and spillage;
- oil processing; and
- wastewater effluent treatment.

Where considerable sediments, suspended solids, and brine are present in the crude oil, gravity separation and chemical and electrostatic desalters are usually employed, resulting in the accumulation of sludge.

Wastes containing oil and petroleum products, heavy metals, and process chemicals require special disposal procedures to limit impact on air, ground, or surface water. Although spent catalysts could be reprocessed, because catalyst solutions or sludges are often diluted and have no market demand, they are removed from the refinery for disposal.

The recent reduction in the release of pollutants to the air and water has led to the recovery of larger quantities of residuals per unit of production. In previous years, ocean dumping, deep well injection, and evaporative lagoons were common practices, but recent regulations tend to restrict the use of these disposal techniques. Fluid bed incineration is now being used.²⁷ The sludge is burned, reduced in volume, and the resultant ash, residue and fines and par-

²⁷ EPA, Development Document for Effluent Limitations, p. 98.

Characteristics, Requirements, and Impacts (continued)

TABLE 6.16
SOURCES AND CHARACTERISTICS
OF REFINERY SOLID WASTE

<u>Type of Waste</u>	<u>Sources</u>	<u>Description</u>	<u>Characteristics</u>
Process Solids	Crude oil storage, desalter	Basic sediment	Iron rust, iron sulfides, sand, water, oil
	Catalytic cracking	Catalyst fines	Inert solids, catalyst particle carbon
	Alkylation	Spent sludges	Calcium, flouride, bauxite, aluminum chloride
	Drying and sweetening	Copper sweetening residues	Copper compounds, sulfides, hydrocarbons
	Storage tanks	Tank bottoms	Oil, water, solids
	Slop oil treatment	Precoat vacuum filter sludges	Oil, diatomaceous earth, solids
Effluent Treatment Solids	API separator	Separator sludge	Oil, sand, and any of the above process solids
	Chemical treatment	Flocculant aided precipitates	Aluminum or ferric hydroxides calcium carbonate
	Air flotation	Scums or froth	Oil, solids, flocculants (if used)
	Biological treatment	Waste sludges	Water, biological solids, inerts
General Waste	Water treatment plant	Water treatment	Calcium carbonate, alumina, ferric oxide, silica
	Office	Waste paper	Paper, cardboard
	Cafeteria	Food Wastes (garbage)	Putrescible matter, paper
	Shipping and receiving	Packaging materials, strapping pallets, cartons, returned products, cans, drums	Paper, wood, some metal, wire
	Boiler plant	Ashes, dust	Inert solids
	Laboratory	Used samples, bottles, cans	Glass, metals
	Plant expansion	Construction and demolition	Dirt, building material, insulation, scrap metal
	Maintenance	General refuse	Insulation, dirt, scraped materials-valves, hoses, pipes

SOURCE: Impacts of an Oil Refinery Located in Southeastern New Hampshire, Chapter 3 (UNH, 1974), p. 8.

Characteristics, Requirements, and Impacts (continued)

ticulate matter collected from the smoke stack are transported to a landfill for burial.

Because of the need to remove impurities from the crude oil stream, the same amount of crude oil pretreatment would be necessary, independent of the final refinery products required (e. g., brine would have to be removed in all cases). Therefore, sludges from storage and from the desalter process would be approximately constant in volume independent of subsequent refinery processes.

Chemical slurries of oil with alum and other chemicals are produced as a consequence of the removal of oil from the brine wastewater stream. For example, when ferric chloride is used to remove oil from water, approximately four cubic feet of sludge are generated for each pound of chemical used. In order to obtain 50 parts per million oil in the discharge water, 30 to 500 pounds of ferric chloride is used per day to treat 10,000 barrels of water.²⁸ Therefore, in the oil/water separation process of a 10,000 barrel per day refinery, at least 120 cubic feet of oiled sludge would be generated per day.

The amount of sludge generated by refining processes depends upon the kind and degree of processing; quantities of biological sludges have been estimated for small and large refineries by subcategory in Table 6.17.

If adequate treatment and disposal facilities exist, refinery solid wastes should cause no serious environmental consequences. If such facilities are not available, they will be required in order to avoid environmental damage that could occur as a result of the use of inadequate hazardous waste disposal sites (see Appendix A).

Small spills of oil will occur periodically and, together with the process, bilge, ballast and runoff water effluents, constitute sources of oil pollution in the receiving waters. Although large spills will occur less frequently, because they are inevitable, major attention is directed toward containment and treatment methods.

²⁸ EPA, Control of Oil, pp. 3-9.

Characteristics, Requirements, and Impacts (continued)

TABLE 6.17
GENERAL RANGE OF BIOLOGICAL SLUDGE QUANTITIES
GENERATED BY SMALL AND LARGE
REFINERIES IN EACH SUBCATEGORY¹

Subcategory	Cu. m. /yr. ²	Cu. yd. /yr. ²
Topping	2.3-15	3-20
Low Cracking	76-380	100-500
High Cracking	380-2300	500-3000
Petrochemical	460-3800	600-5000
Lube	610-6900	800-9000
Integrated	760-9200	1000-12000

¹ These figures do not include storage or process sludges.

² Wet-weight basis.

SOURCE: U.S. EPA, PB-238-612, Development Document for Effluent Limitations Guidelines and New Source Performance Standards for the Petroleum Refining Point Source Category, prepared by M. Halper, (1974), p. 140.

Crude oil and petroleum products are most commonly spilled into near-shore waters, which often contain dense plant and animal populations and may serve as nursery and spawning grounds for many marine animals. When large-scale spills coincide with breeding periods, the impact on the population can be severe. Long-term, low-volume discharges can be expected to produce different consequences than single large-volume spills. Aromatic oil compounds are especially toxic, and the proportion of these substances in a crude or product mixture will determine its overall toxicity.²⁹

Unless the existing biota has already been altered from constant exposure to oil discharges (e.g., an urban harbor), changes can occur in the species composition of organisms in or on receiving waters that receive discharges and spills from the refinery, whether those organisms spend their entire life or only a portion of it (e.g., larvae or juvenile or migra-

²⁹ National Academy of Sciences, Petroleum in the Marine Environment, (Washington, D. C.), 1975.

tion or spawning period) near the refinery discharge. The effects of oil spills on marine organisms are discussed in detail in Appendix A.

Fire Hazards and Controls

Fire presents a particularly acute danger where large volumes of petroleum are stored, as is the case at the dockside facilities, at the tank farm, and at the refinery. Although a fire itself may be small and easily contained, the intense heat generated by the combustion of crude oil and petroleum products presents the distinct potential for explosion.

Consequently, although the frequency of fires may be low, extensive precaution and control is exercised. One proposed storage facility in Scotland³⁰ includes the following fire prevention equipment. Fire alarms are placed in the tank area and in the main control room. A complete water system for fire fighting is included in the storage area, in addition to portable dry powder extinguishers. A foam fire extinguishing system is also included which may be used throughout the tank farm.

Storage tanks are also often equipped with individual foam systems, which, when triggered, can contain a fire by covering an entire tank with foam. In addition, each tank is diked, to prevent a fire from spreading.

In the United States, fire protection systems for tank farms must meet the requirements of the National Fire Prevention Association and the Federal Occupational Safety and Health Act. Individual states may also have specific fire prevention regulations.³¹

Dockside fire prevention systems are also extensive. The self-contained systems include a pumping station, foam system, and distribution piping. In addition, seawater may

³⁰ Planning Application for Sullom Voe Marine Terminal, Shetland Islands, Scotland, 1975, Appendix, pp. 1-2.

³¹ Petroleum Development in New England: Economic and Environmental Considerations. Prepared by Arthur D. Little, Inc., for the New England Regional Commission, (November, 1975), Vol. 2, p. IV-410.

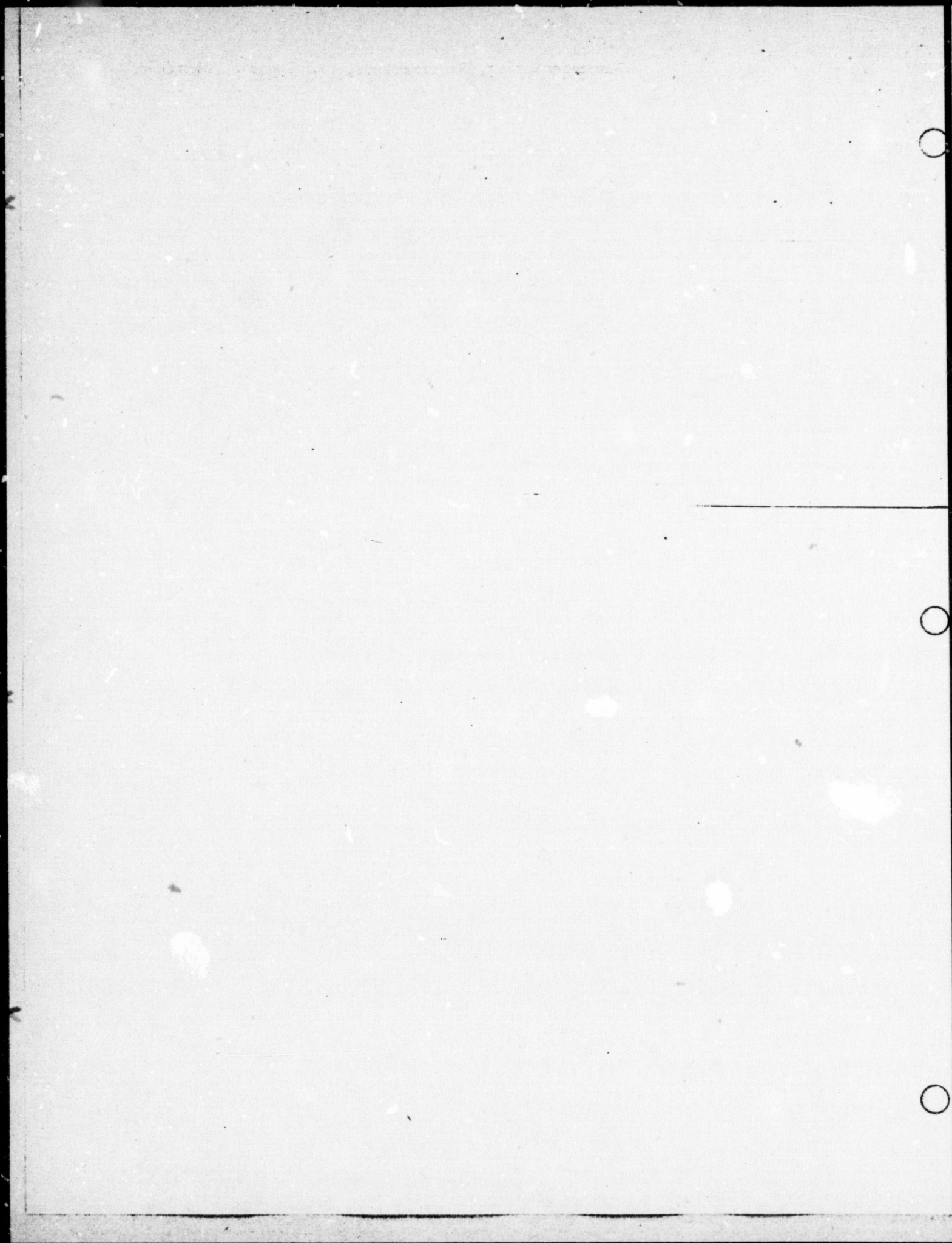
Characteristics, Requirements, and Impacts (continued)

be used directly and is drawn by turbine fire pumps. Under-deck and pile protection by water fog and water sheet systems is supplied for the loading platforms.³²

Aesthetic Impacts

Aesthetic impacts of an oil refinery include odor, and visual impacts from 24-hour lighting, storage tank cooling towers, and processing units. These impacts can be lessened, and environmental damage minimized, by proper site selection, plant location, and design techniques.

³² Ibid, p. IV-32.



**SUMMARY OF REQUIREMENTS AND IMPACTS
FOR A RANGE OF UNIT SIZES AND TYPES¹**

	250,000 bbls/day		500,000 bbls/day	
Fuel Mix ²	Low	High	Low	High
<u>Operation Phase</u>				
Land Area (acres)	1000	1000	1750	1750
Water (million gal/day)				
withdraw	13.2	10.5	26.4	22.1
consumed ³	5.4	4.5	10.7	9.3
Power				
Electric (kwh/day)	1,818,000	1,446,000	3,636,000	2,982,000
Fuel Oil (bbls/day)	24,330	19,790	48,660	40,380
Employment				
Total Direct	435	410	620	590
Local Labor Pool ⁴	374	353	533	507
Employment by Type (%)				
Administrative	18.4	19.4	15.3	16.1
Operative & Maintenance	70.1	68.3	72.6	71.2
Other (Laboratory, Safety, etc.)	11.5	12.2	12.1	12.7
Wages⁵				
Total Direct (\$ thousand)	6,705	6,345	9,505	9,070
Total Local (\$ thousand)	5,766	5,457	8,174	7,800
Average/man (dollars)	15,250	15,250	15,250	15,250
Average Adminis.	18,750 -	18,750 -	18,750	18,750
	19,250	19,250	19,250	19,250
Average Opr. & Main.	14,500	14,500	14,500	14,500
Average Other	15,500	15,500	15,500	15,500
Capital Investment (\$million)	815	690	1,515	1,285
Annual Operating Costs (\$ million)	68.5	58.3	125.2	107.1
Local Taxes (\$ million)	7.0	5.8	12.9	10.7
Transportation				
(Operation)				
Auto ⁶	218	205	310	295
(Round Trips/Day)				

Truck

Rail

Information unavailable at printing.

Waterway

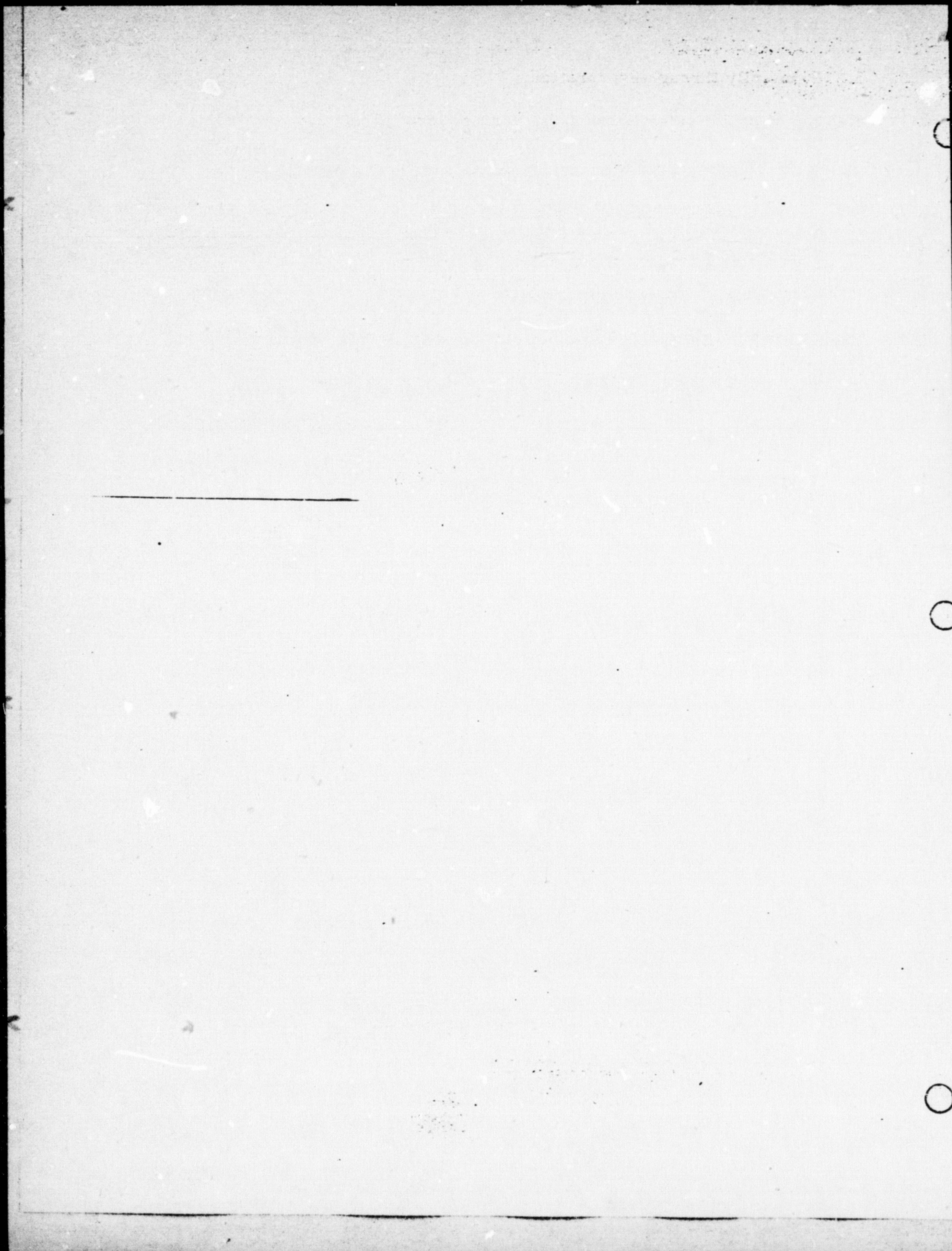
Construction Phase

Total Time ⁷	4	4	4	4
Actual Construction Time	3	3	3	3
Costs (\$ million)	700	580	1,285	1,065
Employment				
Total Direct	2,180	1,800	1,285	1,065
Local Labor Pool ⁸	1,526	1,260	2,793	2,268
Total Wages (\$ million)	46,135	38,500	84,425	69,300
per year				
Local Wages (\$ million) ⁹	32,295	26,950	59,098	48,510
Average	21,160	21,390	21,160	21,390
Power				
Electric				
Fuel Oil	NA	NA	NA	NA
Water	NA	NA	NA	NA
Transportation				
Auto 10	The UNH study predicts a total of 62,700 shipments to refinery over construction period. It cannot be determined if all shipments would be by truck or if some would be by rail or water.			
Truck				
Rail				
Waterway				

1. Unless otherwise noted, data derived from "Effects on New England of Petroleum Related Industrial Development," Arthur D. Little, Volumes 3 and 4.

2. The Little study uses two fuel mixes to identify various cost differences based on complexity - A High Fuel mix is 33% gasoline, 4% kerosene/jet fuel, 27% distillate fuel oil, and 36% residual oil. A Low Fuel mix is 43% gasoline, 5% kerosene/jet fuel, 36% distillate fuel oil, and 16% residual oil.

3. Primarily through evaporation.
4. Based on Little estimate of 86 percent local hire.
5. Local wages are 86 percent of total wages; see "4" above.
6. Round trip/day based on two workers per car--source of Figure 2 is "The Design and Construction of an Oil Refinery," The Impacts of an Oil Refinery Located in Southeastern New Hampshire, Chapter 2 (University of New Hampshire, 1974).
7. Total time consists of one year for design and three years for construction.
8. Based on Little estimate of 70 percent local hire.
9. Local wages are 70 percent of total wages; see "7" above.
10. Based on 70 percent if workers commuting with two per car; see "9" above.



STEEL PLATFORM FABRICATION YARDS
SUMMARY OF REQUIREMENTS AND IMPACTS

Land:	400-800 acres
Depth at Wharf:	15-30 feet
Sea Access Clearances:	210-350 feet (horizontal and vertical)
Water:	100,00 gal/day at a steel platform yard, employing 1,500 workers
Energy:	not available
Labor:	250-550 per steel platform (average)
Wages:	\$30 million total per year at a steel yard (2-4 platforms/year); average wage \$19,000
Air Emissions:	sand and metal dust from sand blasting hydrocarbons and other organic compounds from paint evaporation; carbon monoxide, sulfoxides, hydrocarbons, and nitrogen oxides from vehicles;
Wastewater Contaminants:	heavy metals; particulates, anti-fouling chemicals.
Noise:	80-100 decibels on a 24-hour basis
Solid Wastes:	packaging materials, metal scraps, contaminated debris

CONCRETE PLATFORM FABRICATION YARDS

SUMMARY OF REQUIREMENTS AND IMPACTS

Land:	20-50 acres per platform
Depth at Wharf:	20-40 feet minimum; 35-50 feet preferred
Sea Access Clearances:	over 400 feet (vertical)
Water	40,000 gal/day at a one-platform concrete yard (165,000 gal/day at peak activity)
Energy:	3 megawatts at a one-platform concrete yard; 45,000 gal diesel fuel stocked at a one-platform concrete yard; 11 tons gas stocked at a one-platform concrete yard
Labor:	350-450 average; peak 600-1200
Wages:	\$8.8 million total per year (1 platform); average wage \$19,550
Air Emissions:	sand and metal dust from sandblasting, dust from cement storage silos and concrete mixer plant; hydrocarbons and other organic compounds from paint evaporation; carbon monoxide, sulfoxides, hydro carbons, and nitrogen oxide from vehicles
Wastewater Contaminants:	heavy metals, particulates, anti-fouling chemicals
Noise:	80-100 decibels on 24-hour basis
Solid Waste	packaging materials, metal scraps, contaminated debris

8.16

*Characteristics, Requirements, and Impacts (continued)*Labor Availability
and Restrictions

The proximity and availability of a labor pool is not a critical determinant in the siting decision, but it can have an effect. All other factors being equal, the availability of skilled workers could determine the specific site for a new facility. More important, however, are the labor restrictions established by local labor organizations. For example, if restrictions are tight (if welders are only permitted to weld, mechanics only allowed to perform certain, specific mechanical tasks, a foreman restricted to non-labor activities), then the fabricator may go elsewhere. Because of labor restrictions, many fabricators prefer not to work with labor unions, and will seek a pool of non-restricted labor instead. Percentages of union and non-union labor vary considerably with each fabricator.

Climatic
Conditions

Since most fabrication work is done either outside or in large open sheds, adverse weather conditions can have a significant effect on productivity and, ultimately, profits. While productivity and profit per work day are directly proportionate to the number of warm days, the climatic factor is not critical. In the rigorous Scottish climate, for example, fabricators have erected temporary shelters over the part being constructed.

Rain, in itself, poses a minor threat, although a combination of rain, storms, wind, and high seas can hinder production. High winds, in particular, would halt all operations controlled by cranes.³

CHARACTERISTICS
REQUIREMENTS,
AND IMPACTS

Once the decision is made to site a new facility, it is necessary to find a reasonably sized and situated piece of level land within economically viable distances from offshore installation sites: an area that also has easy access to water

3 Correspondence with Sea Platform Constructors (Scotland) Limited, July, 1976.

deep enough to move the platforms from the yard to open water and on to the installation site.⁴

Much of the information presented below is drawn from impact statements prepared for Brown and Root's proposed steel platform fabrication yard in Cape Charles, Virginia, and is appropriately footnoted. This facility, at peak, would produce roughly nine steel platforms at any one time.

Land
Requirements

Technically, the amount of land required for a steel platform fabrication yard depends upon the maximum number of platforms likely to be constructed at any one time during the life of the facility. On the other hand, the amount of land the company actually purchases, or leases, depends on many other factors, including cost, availability and required expansion room. The smallest facility is roughly 50 acres, but the larger yards require between 200 and 600 acres. Some yards are considerably larger. Brown and Root proposes to use 980 acres of a 2000 acre site in Virginia.⁵

The availability of the land can have an important effect on the size of the yard, initially and during later expansion. If the land at the chosen site is abundant and inexpensive, the fabricator will be more likely to option or purchase a larger parcel than if the availability were limited or price high. Many fabricators prefer short-term lease options, with renewal clauses stipulating no maximum lease period and stating the availability of additional options, should site expansion be required.

Land Use Patterns. Land use in the platform fabrication yard can be roughly separated into fabrication and storage-support. Approximately 50 to 60 percent of the land in the yard is allocated to fabrication, and 45 percent to storage-support. Table 8.3 provides a breakdown of facilities in each category of land use.

4 Nelson, "Manufacturing Opportunities p.

5 Urban Pathfinders, Inc. Brown & Root Impact Study. February 1975. pp. i-ii.

PIPE COATING YARDS

SUMMARY OF REQUIREMENTS AND IMPACTS

Land:	100-150 acres (30 for a portable plant)
Marginal Wharf:	750 feet
Depth at Wharf:	at least 10 feet, preferable 20 to 30 feet
Water:	15,000 gallons per day
Energy:	1 million KWH; 12-13 million cu ft/yr natural gas
Labor:	100-200 people during production season (usually March-September)
Wages:	\$2 million per year at a yard employing 175 people average wage \$11,500
Capital Investment:	\$8-10 million (\$1 million for a portable plant)
Air Emissions:	particulate matter, nitrogen oxides, sulfur oxides, carbon monoxide, hydrocarbons
Wastewater Contaminants:	hydrocarbons, alkaline substances, partic- ulates, metal fragments
Noise:	90-100 decibels (uncontrolled)
Solid Wastes:	packaging materials, concrete, metal scraps, contaminated debris.

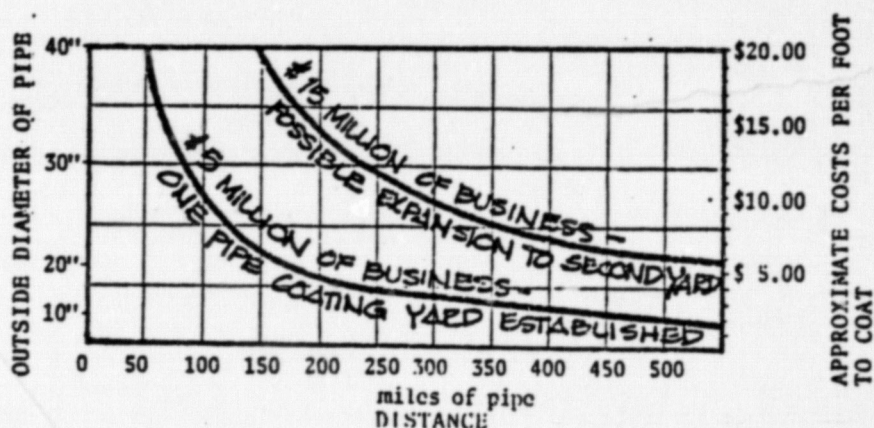


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Timing, Trends, and Options (continued)

Figure 9.2 illustrates the quantity of pipe needed to generate \$5 and \$15 million worth of business, respectively, in terms of distance and diameter. The figure is based on information contained in Table 9.3

FIGURE 9.2
PIPE COATING --
ANNUAL RATES OF BUSINESS IN DOLLAR VOLUMES
POINTS OF START-UP AND EXPANSION



Proximity To
Related
Facilities

Proximity to certain other oil and gas related facilities will influence the siting decision of a pipe coating yard. Easy access to the oil industry service base or the pipe laying firm's base of operations is particularly important, since workboats may operate out of either one and close cooperation with the pipe laying firm is essential.

The pipe coating facilities at Invergordon and Leith, Scotland, Immingham (North Lincolnshire) England and Delfzül, The Netherlands, for example, are sited near platform fabrication yards, service bases, deck and module fabrication yards and heliports.

Labor

The availability of specialized labor is not likely to be a major factor in the siting decision. As much as 90 percent of the total work force at a yard will not require specialized skills.

Weather
Conditions

Since most pipe coating operations take place between April and November, adverse weather conditions will usually not influence the siting decision. However, if pipe needs to be coated year round, precautions must be taken to prevent the mixing, application and curing, water from freezing.

Other Factors

Other factors which will influence the firm's decision to site a yard adjacent to new offshore finds include: distance between the offshore finds and existing competition; ability of existing yards to meet the required delivery schedule of the oil or gas industry for the duration of the operation; expected quantity of work; whether subsequent lease sales can be served from the region; the possibility of competitors locating nearby; access to the source of raw materials and pipe.

CHARACTERISTICS,
REQUIREMENTS
AND IMPACTSLand
Requirements

A permanent pipe coating yard requires between 100 and 150 acres; 30 acres may be sufficient for establishing a portable plant ("railhead operation").

The land area needed may vary considerably depending on the miles of pipe to be coated and the number of years the yard is expected to be in operation. Depending upon storage needs and the availability of suitable land, a pipe coating firm may purchase or lease as much as 200 acres. Existing sites serving the Gulf Coast range from about 75 to 100 acres.

Land Use Patterns. Approximately 95 acres of a 100 acre site are used for storage; the remaining area houses the coating and load out operations. About two acres are usually reserved for the contractor's inspection personnel and their equipment.

Ideally, the pipe coating operation will be located on a single site. However, some sites are bisected by

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Interim Land Use and Density Guidelines for the Coastal Area of New Jersey

Let's Protect Our Earth.



PLAINTIFFS
EXHIBIT
T 225
7/10/2001

State of
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Department of
Environmental Protection
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Public Safety
Office of
Zoning and
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Bureau of
Planning
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State of New Jersey
DEPARTMENT OF ENVIRONMENTAL
PROTECTION
TRENTON

DIVISION OF MARINE SERVICES

PLEASE ADDRESS REPLY TO
P. O. BOX 1889
TRENTON, N. J. 08625

Office of Coastal Zone Management
June 1976

What Are Interim Land Use and Density Guidelines?

Questions and Answers

The Coastal Area Facility Review Act of 1973 (CAFRA) charges the Department of Environmental Protection with preparing comprehensive programs and policies to protect the environment of New Jersey's Coastal Area, while providing for new development which will meet economic and social needs of the Area and the State. The Department exercises final permit review over construction of most major facilities. It is also charged with preparing alternative environmental management strategies for the Area by September 1976, and with submitting a final environmental management strategy to the legislature and Governor by September 1977.

The Interim Land Use and Density Guidelines will serve as Department policy until the final environmental management strategy is selected. They will provide a framework for prospective permit applicants and for Department permit review. These pages answer some questions about the Guidelines.

Two reports have been prepared: Interim Land Use and Density Guidelines and Basis and Background for Guideline Formulation. Copies of both documents are available from the Office of Coastal Zone Management.

1. WHY HAVE INTERIM LAND USE AND DENSITY GUIDELINES?

The Guidelines indicate Department policy prior to the completion of a management strategy. They will restrict discretion and increase certainty in the CAFRA permit application review process.

CONTEXT FOR THE GUIDELINESA. The Coastal Area Facility Review Act

In 1973, the New Jersey Legislature passed and the Governor signed into law the Coastal Area Facility Review Act (P.L. 1973, Chapter 185, N.J.S.A. 13: 19-1 et seq.). This law, commonly known as "CAFRA," charges the Department of Environmental Protection (DEP) with preparing comprehensive programs and policies to protect the environment of an area comprising 1,376 square miles of land along the Atlantic Ocean and Delaware Bay areas of the State. The statutory Coastal Area extends from Raritan Bay and Sandy Hook at the north, south to Cape May and then north and west along the Delaware estuary to the Delaware Memorial Bridge. It ranges in width from a few thousand feet to as much as 24 miles on the landward side of the ocean. CAFRA jurisdiction extends to the three-mile territorial limit along the Atlantic coast, to the New York boundary in Raritan Bay and to the Delaware boundary in Delaware Bay. The Coastal Area encompasses ocean and bay beaches, wetlands, pine forests, the intracoastal waterway, prime agricultural land as well as other important natural features. It also includes old, established residential communities, newly developing suburbs, and the principal ocean-oriented resort and recreation communities of the State.

CAFRA requires that the Department of Environmental Protection take certain planning and regulatory actions to preserve environmental assets in the Coastal Area, while providing for new development which will meet economic and social needs of the Area and the State.

Principal deadlines for planning actions stipulated under CAFRA are:

September 1975, presentation of an environmental inventory of the Coastal Area to the Governor and Legislature.

September 1976, presentation of alternative long-term "environmental management strategies" for the Area, to the Governor and Legislature.

September 1977, selection by the Commissioner of the approved management strategy for the Coastal Area from the alternative strategies, to be presented to the Governor and Legislature.

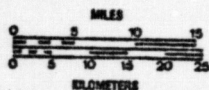
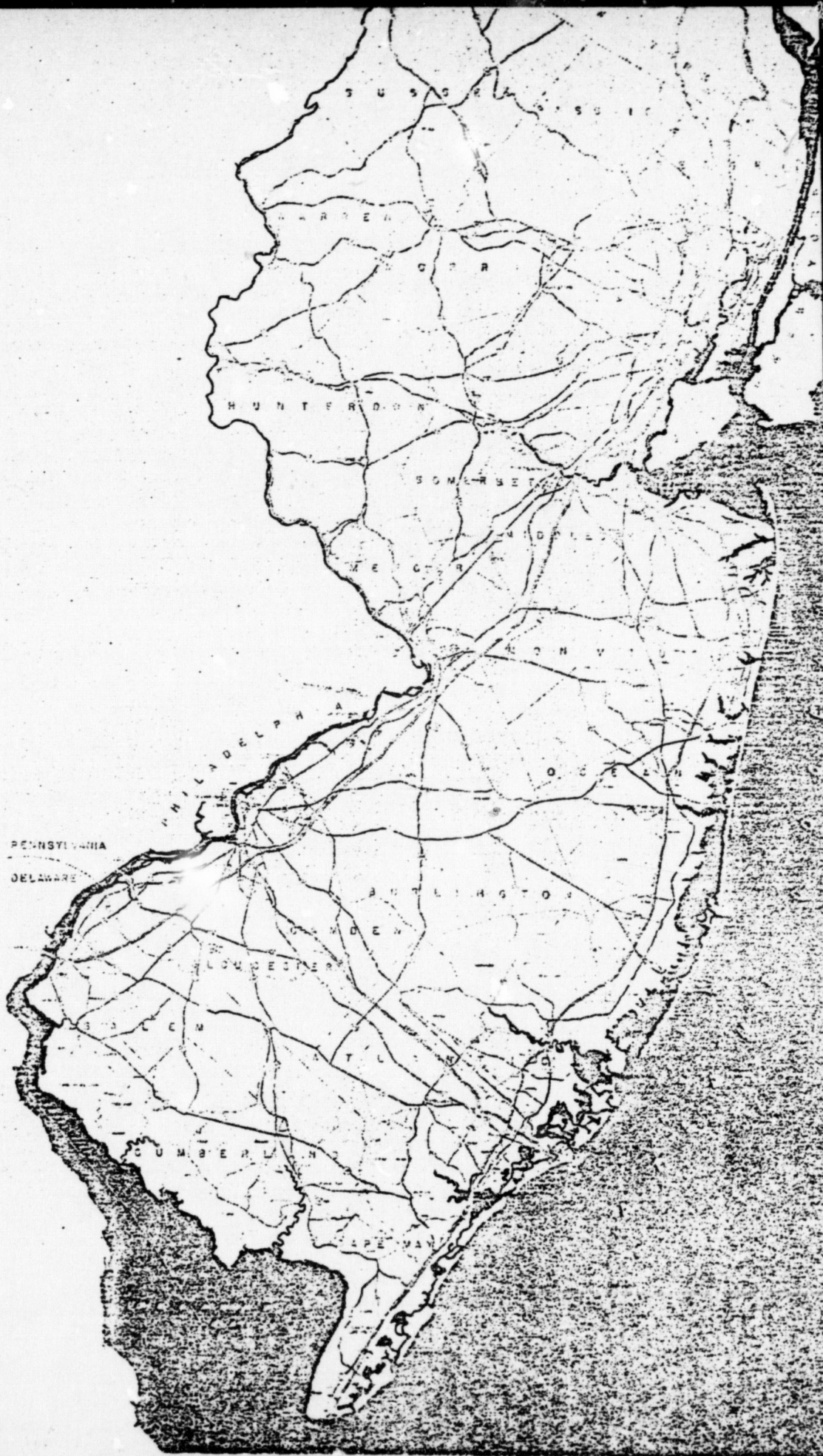
On September 19, 1975, DEP submitted the required environmental inventory to the Governor and Legislature and distributed to the public a report depicting its contents.

CAFRA also stipulates that DEP have final jurisdiction over proposals (both private and public) for specific facilities which could have significant impact on the Area. These facilities include most major residential (25 or more dwelling units), industrial, transportation,

THE COASTAL AREA OF NEW JERSEY

Outside Coastal Area

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Scale 1:1,075,000

INTERIM LAND USE AND DENSITY GUIDELINES
STATE OF NEW JERSEY
DEPARTMENT OF ENVIRONMENTAL PROTECTION
OFFICE OF COASTAL ZONE MANAGEMENT

1975

utilities, and energy-related construction. Permits from DEP are required before construction may begin on any such facility or use. While the applicant must meet all relevant local zoning, subdivision and other requirements, DEP has the responsibility to approve, disapprove, or approve with conditions, the final submission. It has exercised this authority since the Act took effect on September 19, 1973.

Each application for a permit must contain detailed information about the proposed facility or use in the form of an environmental impact statement that describes the project and assesses its implications for the immediate vicinity and the Coastal Area. The several divisions of DEP, the Department of Community Affairs (DCA) and Department of Labor and Industry (DLI), along with other state, county, and municipal agencies participate in the permit application review process, administered by the Division of Marine Services of DEP.

B. Highlights of the Permit Process

CAFRA stipulates (Sec. 7) the basic information to be included in the Environmental Impact Statement and the findings which the Commissioner must make to issue a permit (Sec. 10). CAFRA also authorizes the Commissioner to deny or conditionally approve a permit application if the proposed facility would violate the purpose of the statute (Sec. 11). The Department may request additional information to correct deficiencies in the applicant's initial submission. A public hearing date is set for no later than 60 days after the application is declared complete for filing. After the hearing, DEP can either ask for further information or proceed directly with its final review. In the latter case, the applicant must be notified of the final decision within 60 days of the hearing. If more information is requested, a decision is required within 90 days of receipt and acceptance of that information.

With the passage of the "90-Day Act" in 1975 (P.L. 1975, c. 232), the following additional provision applies to applications submitted after December 22, 1975: Any application will automatically be deemed approved, if a decision on the application is not made during the stipulated 60 or 90 day time periods. Thus all applications may now expect expeditious processing.

The Department has instituted an optional "pre-application" conference to enable a potential applicant to meet with DEP staff at an early date, review the prospective project, and discuss the environmental impact statement requirements. As the result of that conference, some flexibility may be established as to the degree of detail necessary for the specific environmental impact statement submission.

Through April 23, 1976, DEP had received 157 CAFRA permit applications for projects in the Coastal Area. One hundred had been acted upon. Ninety-three had been approved with or without conditions, and seven had been denied. Twenty had been withdrawn, and 37 were pending.

D. Other Regulatory Systems

In addition to CAFRA, various local and state regulatory powers apply within the Coastal Area. Section 19 of the Act states:

"The provisions of this Act shall not be regarded as to be in derogation of any powers now existing and shall be regarded as supplemental and in addition to powers conferred by other laws including municipal zoning authority."

Thus, while CAFRA gives DEP final authority over certain facilities in the Coastal Area, conformance is also required with such local controls as zoning, site plan review, and subdivision, before construction may begin.

Although any project approved under CAFRA must meet local codes and ordinances, the Appellate Division of the Superior Court of New Jersey has upheld the Department's denial of locally-approved projects which are inconsistent with the Act and with Departmental guidelines. In upholding the Toms River denial, the Court stated:

"The police power of the State was not exhausted by the delegation of zoning power to municipalities wherein they were authorized to adopt zoning ordinances. The State with its reserve police power has the unquestioned authority to delegate that power to one or more agencies of governments as the Legislature may deem appropriate....

Furthermore there is no unlawful conflict or pre-emption problem between the permit power granted to the Commissioner and the zoning power of the municipality which governs the project involved herein. To require a developer to comply with local zoning regulations pertaining to land use and also to comply with use regulations designed to protect State environmental resources is not violative of any constitutional mandate. The additional burden cast upon an owner of coastal lands requiring compliance with environmental standards is a valid exercise of State police power.

The absence of zoning guidelines as such in CAFRA does not invalidate the legislation in any respect. The function of CAFRA, as already noted, is to preserve by regulation the coastal resources of the State; the guidelines are incorporated in the legislative standards for the grant or denial of a permit. These standards are manifestly appropriate for the function and purpose of this

legislation and need not be couched in the same terms as zoning legislation to withstand legal attack."

Under the Wetlands Act (N.J.S.A. 13:9A-1, et seq.), the Department must issue a permit before any development may take place on delineated wetlands. (These are excluded from the CAFRA permit reviews.) Other significant DEP review and permit powers deal with development on any waterfront or tidal or navigable waterway (riparian permits), stream encroachment and sanitary sewer systems, and air pollution control.

The management strategy for the Coastal Area, whose preparation is mandated in CAFRA by 1977, is not bound by the nature of existing regulatory authority or intergovernmental relations. It must reflect a comprehensive assessment of the physical, economic, and social situation in the Coastal Area and provide guidance to all levels of governmental activity.

E. The Federal Coastal Zone Management Program

In 1972, Congress passed a Coastal Zone Management Act. This Act supplements and supports the exercise of State powers under CAFRA. This Act encourages all coastal states and territories to establish a management program. The federal Office of Coastal Zone Management in the Department of Commerce provides support funds for studies and activities leading to the formation of each state's management program for its coastal zone and will provide further funds to assist the administration of federally approved management programs. To obtain federal approval of its management program, each state is required to define, among other matters:

"Permissible land and water uses, which have a direct and significant impact on coastal waters" (Sec. 920.12)¹

"Geographic areas of particular concern" (Sec. 920.13)¹

"Designation of priority uses within specific geographic areas throughout the coastal zone" (Sec. 920.15)¹

The formulation of interim land use and density guidelines under CAFRA by DEP is an integral element of New Jersey's efforts under the federal Coastal Zone Management Act. These planning efforts extend geographically beyond the Coastal Area designated in the CAFRA statute. For the purposes of program development under the federal Coastal Zone Management Act, DEP is engaged in a planning process for the entire coast of New Jersey, from the George Washington Bridge in the Hudson River to Trenton on the Delaware River. These interim land use and density guidelines pertain only, however, to the Coastal Area defined by CAFRA.

1. Part 923, Coastal Zone Management Program Approval Regulations, Federal Register, Thursday, January 9, 1975, Vol. 40, No. 6, Part 1.

D. Stimulate Growth and Rehabilitation of Depressed Areas

Some communities within the CAFRA Area have severe economic difficulties. To the greatest degree possible, new employment-generating uses such as light industry or offshore drilling support facilities should be directed towards these communities. At the same time, extensive residential and commercial redevelopment and rehabilitation should be induced to improve housing conditions and provide competitive business advantages. Through flexible treatment of informational requirements in CAFRA applications, the DEP permit-issuing power will be utilized as an incentive. Atlantic City, Asbury Park, Keansburg and other centers which suffer special problems of poverty and physical decline will have special priority for development within the Coastal Area.

E. Accommodate Major Coastal-Dependent Energy-Related Facilities X

In the short-term, other than housing and support facilities, the most likely growth pressures will stem from energy-related facilities: nuclear and fossil fuel power plants, liquified natural gas re-gassification plants, and Outer Continental Shelf (OCS) staging and support complexes. Considerable controversy surrounds present proposals for many of these facilities. All the evidence is not yet in hand, but certain projects may well be deemed of statewide and national importance and dependent on locations in the Coastal Area. Reasons for dependency would be required access to the waters of the ocean and bays and availability of sufficient land area in specific locations to provide protective buffers for resident population—a setting not available elsewhere in New Jersey. At the same time, however, some of these facilities may induce impacts on wetlands, may create certain environmental hazards, and may place strains on housing and community services. Only with appropriate advance planning and commitments to mitigating actions should actual development be permitted. The Department will require such planning and commitments as the basis for any location approvals.

In December, 1975, the Governor and the Commissioner of DEP issued a "Request for Information" to all agencies and companies with intentions to locate or expand any form of energy-related facility within the CAFRA boundaries. When that material has been received and evaluated, the Department will prepare and publish an estimate of energy facility demands in the Coastal Zone (including the wider area under study through the federal CZM program) and will adopt appropriate policies towards locating facilities or restricting areas from facility location. Pending completion of this review, it will be premature to establish guidelines on the location of energy-related facilities.

Nevertheless, the nature and extent of information to be required from any applicant for an energy facility within the Area can be spelled out within the Department's interim guidelines policy.

challenge the Department's position, and to appeal an adverse ruling. This sanction may be relaxed only in the case of energy facilities or other projects of compelling and demonstrated state-wide importance and coastal dependence. Such projects will, however, need to meet extremely detailed submission requirements over and above the Environmental Impact Statement. These requirements are spelled out in the guidelines.

GUIDELINES I: MAJOR FACILITY TYPES NOT CURRENTLY PRESENT IN THE COASTAL AREA

Until preparation of the long-term environmental management strategy in 1977, the Department will discourage from the Coastal Area any major facility which does not require a location within CAFRA boundaries to function effectively and which generates adverse environmental impacts. The kinds of environmental impacts considered include serious air or water pollution, disruption of major natural features such as wetlands and beaches, and traffic congestion. The following location test will be applied to determine whether the facility can be so categorized.

Two conditions must each be met for a facility type to be classified as presently non-dependent on a Coastal Area location:

- a. No examples of the facility type must currently exist and be in operation within the CAFRA boundaries. The land use pattern as depicted in the most current data available to DEP will be examined to determine the presence or absence of the facility type.
- b. Examples of the facility type must be found existing and in operation elsewhere within the State of New Jersey-- either inland from the CAFRA boundaries or in coastal locations that are outside DEP's CAFRA jurisdiction.

Examples of such facilities are oil refineries; commercial ports and marine terminals; and heavy industrial operations such as rendering plants, metals processing; and textile production. Each of these exist in New Jersey, but primarily in coastal locations outside the CAFRA boundaries and considerably closer to the metropolitan areas of Newark-New York and Philadelphia-Camden-Trenton. Infra-structure has been installed to service the facilities, and expansion room for additional installations may well be available in these areas, either through re-development or aggregation of additional land. Based on past experience, these facility types do not evidence dependency

on location within the Coastal Area. Each of those cited represents major land-consuming activities which generate substantial negative environmental impacts on surroundings, wherever they might be.

The facility types to be screened in this manner are among those identified in Section 3C of the CEFRA legislation. Any proposals for such facilities will be diverted elsewhere in the State or deferred until after 1977, in the absence of compelling justification of state-wide significance.

Certain major facility types of potentially critical State importance may not currently be present either in the Coastal Area or elsewhere in New Jersey. In this category are support complexes for Outer Continental Shelf (OCS) oil and gas exploration and re-gassification plants for liquified natural gas (LNG) shipped from abroad. It is possible that site applications for such facilities may be made during the interim guidelines period. Such facilities will be required to demonstrate dependency on a Coastal Area location, lack of viable sites elsewhere in the State, and compliance with policies expressed in the interim guidelines.

GUIDELINES II: LAND AND WATER FEATURES OF THE COASTAL AREA CLASSIFIED AS TO SUITABILITY FOR PRESERVATION, CONSERVATION, AND DEVELOPMENT

To provide area-wide interim guidance, the land and water features of the Coastal Area have been classified in terms of relative suitability for development. All applications which incorporate features in the Preservation category will be discouraged. All applications which incorporate features in the Conservation category will be restricted. All applications which incorporate features in the Development category will be encouraged.

PRESERVATION

These are land and water forms of the Coastal Area which have exceptional, unique, irreplaceable, or overriding environmental importance to the ecology of the Area itself and to the people of the State. These features should be preserved in their present condition or managed to protect or enhance that condition, at least during the interim guideline period. Such action will serve to:

- reduce adverse environmental effects of development and the public costs to mitigate such effects
- enhance the production of valuable aqua resources such as shellfish and finfish

- enhance the natural character of the Area for residents and tourists
- promote recreational activities such as sport fishing

Only under conditions where the Department determines that overriding State economic or social values are to be served might development be allowed. Moreover, should facilities seek locations adjoining such land and water forms, undeveloped buffer areas may be appropriate. The land and water forms so classified primarily represent those singled out by the Legislature in CAFRA as constituting together "an exceptional, unique, irreplaceable, and delicately balanced physical, chemical and biologically acting and interacting natural environment."

A. Coastal Waters and Bays

Under CAFRA jurisdiction, these extend to the three-mile limit in the Atlantic Ocean and to the State Line in Delaware Bay and Raritan Bay.

B. Rivers, Streams, and Lakes

These include all other watercourses within the Coastal Area boundaries.

C. Wetlands

These include both coastal and inland wetlands. Coastal wetlands are defined and controlled under the Wetlands Act (N.J.S.A. 13.A-1, et seq.) rather than CAFRA. Some inland wetlands (marshlands, swamps and natural bogs) are not so controlled but are covered under CAFRA. They are defined as low, poorly drained areas characterized by water-tolerant vegetation and predominantly internal drainage.

D. Barrier Beaches and Dunes

These include the beach and fore and back dune portions of all barrier islands between Sandy Hook and Cape May.

E. Shoreline and Beach

These include all shoreline and beach areas exclusive of those on barrier islands, both ocean and bay.

F. Prime Forest Areas (White Cedar Stands)

Although much of the inland CAFRA area is covered with forests, the White Cedar Stands have been identified by DEP research as of particularly significant and unique environmental value. In the course of final strategy preparation, other species or methods for classifying prime vegetation may also be so identified, and other forms given Preservation status.

G. Natural Areas in Public Control

These are designated wildlife refuges, fish breeding areas and associated lands that have been brought under public ownership and are maintained in a wilderness state. They include the national wildlife refuges (e.g., Brigantine and Killcahook) and all the State fish and wildlife management areas in the Coastal Area.

ISSUES AND INFORMATION RELATING TO ENERGY FACILITIES AND THEIR IMPACTS

The type, number, location and scale of energy-related facilities which may be located in the Coastal Area hold significant impacts for the environmental condition and well-being of the State. Issues surrounding these facilities extend beyond the Coastal Area and the State as a whole. They are national in scope and affect the entire society. Some of these questions may be resolved through the evaluation of the submissions produced in response to the Call for Information issued by the Governor and the Commissioner of Environmental Protection in December, 1975. Other questions may be impossible to answer until more detailed knowledge is available about specific undertakings, such as the true extent of oil and gas deposits on the Outer Continental Shelf. The Department is deeply concerned about matters of safety to workers and residents and of impact on the coastal environment and economy.

Numerous kinds of facilities are under some form of consideration: additional nuclear power plants and fossil fuel power plants; support complexes for Outer Continental Shelf oil and gas exploration; pipelines to carry any OCS finds to refineries and processing plants in the Newark and Camden areas; liquified natural gas storage and processing facilities. Given the nature of the issues and the state of knowledge, the Department believes that formulation and dissemination of detailed site selection and performance guidelines would be premature at this time. Indeed, the formulation of such guidelines is to be a priority matter in the preparation of the overall Coastal Area management strategy. While these guidelines are being established, however, in consultation with governmental agencies at all levels, the interested companies, and citizen groups, the Department will insist that any application for an energy related facility in the interim demonstrate incontrovertibly its dependence on a Coastal Area location and provide extensive information on safety considerations, anticipated performance, and impacts.

Unlike housing and most other facilities regulated under CAFRA, energy facilities are subject to a variety of federal controls, licenses, and permits. Federal agencies customarily make in-depth analyses of the potential environmental impacts and of measures to alleviate them. The Department will not duplicate the work of these federal agencies, but will build on the base of information required under the National Environmental Policy Act. DEP will require submission of information vital to the environmental, economic, and social conditions of the Coastal Area that is not normally emphasized in the context of federal review. These guidelines for information shall be as follows:

1. Environmental Impact Statements prepared for federal licenses and permits will be accepted as a major part of the required CAFRA EIS. Under the National Environmental Policy Act (NEPA) the Department will be a review agency for preliminary statements and will influence final assessments.

As a general principle the Department will stress provision of cumulative assessments where relevant: for example, in respect to the potential environmental and economic impacts of several nuclear facilities on Artificial Island and of both off-shore nuclear facilities and Outer Continental Shelf staging areas and pipelines in the Atlantic City area.

2. The CAFRA permit application will require a supplement to provide the following additional information if not detailed within the federal EIS.

a. Evidence of the facility's dependence on a location within the Coastal Area. This would include evidence that no sites outside the Coastal Area are economically feasible or afford lesser environmental impacts.

b. Evidence that the facility location and use conform to state land use and environmental plans and policies.

c. A discussion of the character, degree, and timing of any urban development likely to be induced by the facility in the Coastal Area.

d. A discussion of specific impacts likely to be induced during the construction phase of the facility on:

--housing and community services generated by construction worker and employee demand

--existing business and land uses in the Coastal Area

--local streets and utilities

--local government public services, taxes, and fiscal stability

e. A discussion of long-range (10-20 year) post-construction impacts on local area housing, public services, and government finance.

f. A description of a measurement and monitoring system to be introduced by which both environmental and economic impacts may be periodically checked.

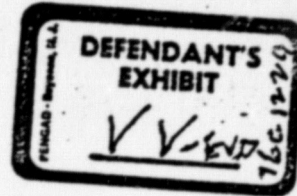
g. A discussion of techniques, governmental responsibilities, and financial measures that may be taken to mitigate negative impacts, both environmental and economic, revealed in the analytic document.

h. A discussion of measures that could be taken to decommission, dismantle, or remove the facility if at a future date it is no longer needed.

United States of America

DEPARTMENT OF THE INTERIOR

Washington, D. C.



I certify that the official records of the Department of the Interior are in my
personal custody and attest that each annexed paper is a true copy of a document
comprising part of the official records of the Department of the Interior:
Copy of a Department of the Interior News Release, dated June 17, 1976,
titled Mid-Atlantic OCS Decision Could Be In Late June.

IN TESTIMONY WHEREOF, I have subscribed my name, and caused the
seal of the Department of the Interior to be affixed on
this 22nd day of July, 1976.

Louis A. Croft
Acting DIRECTOR OF MANAGEMENT OPERATIONS



DEPARTMENT of the INTERIOR

news release

OFFICE OF THE SECRETARY

2952

For Immediate Release (June 17, 1976)

MID-ATLANTIC OCS DECISION COULD BE IN LATE JUNE

Secretary of the Interior Thomas S. Kleppe said today that no final decision will be made on the proposed sale of Outer Continental Shelf oil and gas leases in the Mid-Atlantic Baltimore Canyon Trough area until he has completed his study of the final environmental impact statement (EIS) covering the proposal.

The final EIS was issued on May 26 and submitted at that time to the Council on Environmental Quality (CEQ). A final decision will not be made on the sale until at least late June, or a minimum of 30 days after submission of the EIS to CEQ.

The Secretary discussed the Mid-Atlantic sale and other matters with several reporters Wednesday. He said news reports based upon the discussion failed to clarify that in the event a decision is made to hold the sale, it would not be held prior to August 17. The Secretarial decision as to a sale would not be made until late June after he has completed his review of the EIS.

The Secretary said his comments Wednesday about the possibility of some Alaskan oil being traded to Japan on a short-term basis were in reply to a speculative question asked him by a reporter. No decision on this matter would be possible until trans-Alaska pipeline construction is completed in late 1977 and the supply-demand situation on the West Coast analyzed in light of conditions prevailing at that time. Kleppe said that under the Alaska Pipeline Act of 1973, export of North Slope Alaskan oil would require a Presidential decision, and such a decision could be blocked by a concurrent resolution of the Congress.

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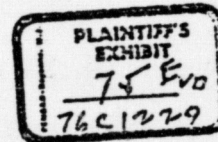
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FEDERAL TRADE COMMISSION
WASHINGTON, D. C. 20560

LEAD OF COMPETITION

MAR 8 1976

Manager
New York OCS Office
Six World Trade Center
Suite 6000
New York, New York 10048



Dear Sir:

This letter is in response to a letter recently received from the Department of Justice which forwarded to the Federal Trade Commission a copy of the "Programmatic PDOD on the OCS Accelerated Leasing Program" in compliance with the direction of the Honorable Jack B. Weinstein, United States District Court Judge for the Eastern District of New York. The direction was made at the plaintiff's request in the case of County of Suffolk et al. v. Department of the Interior et al., Case No. 75-C-208. According to the letter accompanying the PDOD dated January 22, 1976 from Cyril Hyman, Assistant U.S. Attorney for the Eastern District of New York, to Thomas E. Kauper, Assistant Attorney General, Antitrust Division of the Department of Justice:

Plaintiffs [in the case] had requested that the PDOD be provided to the Antitrust Division of the Department of Justice and the Federal Trade Commission so that they would have an opportunity to comment on matters contained in the PDOD which involve "possible anti-competitive practices of the major oil companies regarding OCS leasing and other anti-trust issues relevant to OCS production, distribution, marketing, etc."

Judge Weinstein made no direction concerning the nature of ... [the Federal Trade Commission's]... participation in this matter. His direction to submit a copy of the PDOD to ... [the Federal Trade

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Manager, New York OCS Office

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Commission)... is to provide... [the Federal Trade Commission)... with an opportunity to comment on the PDOD if... [it]... so desire[s].

Since the OCS will play a major role in this nation's future energy programs, I wish to take this opportunity to file comments concerning matters contained in the PDOD statement and forward to you a study prepared by the Bureau of Competition and Economics on past and present federal leasing policy.

The PDOD statement prepared by the Office of OCS Program Coordination lacks analysis of the competitive impact of the proposed accelerated leasing program. It also lacks analysis of the availability of the resources--drilling platforms, pipe, and men--needed to explore and develop at an accelerated pace. This analysis should be performed prior to such an undertaking.

Some insight into the effect of the proposed accelerated leasing program can be gained from the Bureau of Competition and Economics' recently completed report entitled "Report to the Federal Trade Commission on Federal Energy Land Policy: Efficiency, Revenue, and Competition." This report discusses past and present federal policy and its effect on competition. Chapter Six of this report is devoted exclusively to federal offshore oil and gas leasing.

Relevant portions of this report state that:

The major defects of the present OCS oil and gas leasing system stem from impediments to competition caused by the cash bonus bidding system and the prevalence of joint ventures. The bonus bidding system has hindered the entry of smaller petroleum companies. While the high costs of drilling and the risks of oil-spill damage also discourage offshore investment, cash bonus requirements impose a substantial but avoidable barrier. Owing to the constrained rate of leasing in the past, the competition for leases has been sufficient despite the limited ability of independents to bid successfully for leases. If the rate of leasing is accelerated, however, greater participation is essential if competition is to be maintained at a level sufficient to ensure the collection of the leases' fair market value.

The barriers to entry associated with the cash bonus bidding system have also led to the concentration of offshore oil and gas production in the hands of a relatively few large firms. Since those firms are also the largest onshore producers, this could eventually foster an excessively concentrated U.S. petroleum market structure. Since the OCS is expected to provide less than 25 percent of total U.S. oil production in 1985, however, market concentration will continue to be determined to a large extent by the concentration of onshore production.

The cash bonus bidding system has also encouraged the formation of potentially anticompetitive joint ventures. Joint ventures among the major oil companies may further reduce competition, although our leasing study has uncovered no clear evidence that this has actually happened. It has been demonstrated, however, that joint ventures among majors have probably reduced the number of bidders per tract and, by providing information on the bidding intentions of competitors, inhibited the vigor of bidding.*/

The report suggests that regularly scheduled lease sales could be beneficial to smaller independent firms. A regular schedule will enable firms to plan for future lease sales and acquire the capital needed to participate. Smaller firms are disadvantaged when the time for preparation is short because they do not have the capital which is readily available to large firms. The report also suggests that larger lease sales would enable independents to acquire more tracts. When more tracts are offered for sale, bonus bids have a tendency to decrease, enabling smaller firms to compete. Although the report suggests that larger lease sales will enable independents to compete, it questions the validity of the Department of Interior's proposal to lease ten million acres in one year. The successful accomplishment of an increase of this magnitude is doubtful because the materials needed to explore and develop the tracts may not be available.

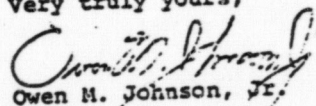
*/ Bureaus of Competition and Economics, Federal Trade Commission, Report to the Federal Trade Commission on Federal Energy Land Policy (1975) at pp. 421-422.

Manager, New York OCS Office

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For your convenience, I have enclosed a copy of this rather voluminous report. I trust that it will be useful to you in analyzing the proposed accelerated leasing program. If I can be of further assistance to you in this matter, feel free to contact me.

Very truly yours,

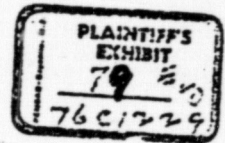

Owen M. Johnson, Jr.
Director
Bureau of Competition

Enclosure

cc: John V. N. Klein
Suffolk County Executive
Suffolk County Executive/
Legislative Building
Veterans Memorial Highway
Hauppauge, New York 11787

UNITED STATES DISTRICT COURT
EASTERN DISTRICT OF NEW YORK

COUNTY OF SUFFOLK, COUNTY OF NASSAU, TOWN OF FELIP,
TOWN OF HEMPSTEAD, TOWN OF NORTH HEMPSTEAD, TOWN OF
OYSIER BAY, TOWN OF HUNTINGTON, and the BOARD OF TRUSTEES
OF THE TOWN OF HUNTINGTON



Plaintiffs

Civil Action
No. 75 C 203

- against -

SECRETARY OF THE INTERIOR and CURTIS J.
BERKLUND, individually and as Director
of the Bureau of Land Management

Defendants

STATE OF NEW YORK)
COUNTY OF HEMPSTEAD) SS.:

ROBERT ENGLER, being duly sworn, deposes and says:

The 1976 proposed lease sale in the Atlantic outer continental shelf shows how little has been learned in defining and defending the public interest. The Department of the Interior, which bears a central responsibility for managing energy and natural resources for the benefit of the American people, still accepts the premises and priorities of the private oil industry concerning energy development and use in the United States. The program decision option document concerning the sale of leases in the mid Atlantic outer continental shelf is essentially a grabbag

of conventional and often unproven conclusions which

- a) assumes that the oil industry is essentially a competitive industry.
 - b) assumes that industry preferences and positions provide adequate boundaries for public policy.
 - c) ignores the need for national energy planning.
 - d) ignores the need to relate such national energy planning to larger considerations as to alternative directions for the American economy.
 - e) accepts the premises of "more and more" energy and productivity without asking how such resources are developed, distributed and used.
 - f) accepts private industry's capital investment desires, based on profit considerations, as the equivalent of the nation's capital investment needs.
 - g) is uncritical about the claims of immediate energy shortages and about the great gaps in independent and reliable information about reserves.
 - h) shows little interest in developing independent information about the reserves of the outer continental shelf and their value.
 - i) reflects an innocence about oil pricing and reflects no interest in these publicly owned resources serving to introduce some public criteria about energy pricing.
 - j) shows no interest in alternative energy sources.
 - k) makes no serious reference to the conservation of energy as an essential part of energy planning.
 - l) fails to consider the public development of resources on public lands.
 - m) discounts the importance of local participation and planning prior to the time of the critical decisions about outer continental shelf leasing.
 - n) places more emphasis upon the ability to deal with oil spills than upon preventing them and upon the daily hazards of offshore drilling.
 - o) shows no recognition of the extent to which present agencies and policies for public control over energy are essentially beholden to the private government of oil.
- The program decision option document thus is thoroughly inadequate as a guideline for the formulation and implementation of public policies .

Oil and gas provide three-fourths of the fuel energy for the United States. The corporations controlling these resources cluster at the top of the list of the nation's largest enterprises. Ranked by assets they occupy five of the first eight positions. The seven worldwide giants (five American - Exxon, Texaco, Gulf, Standard of California and Mobil, and two international - Royal Dutch Shell and British Petroleum) have assets whose combined worth, at a minimum, is \$132 billion. This total barely begins to describe their resources or their economic power. One must also calculate the present and future worth of reserves in the ground as well as the market power in the tremendous capital at the disposal of these corporations through income, depreciation and depletion. They command physical and financial resources greater than those of most industries and many nation states.

As of 1970 the first 20 oil companies (the major integrated companies) accounted for 94 percent of domestic reserves, 70 percent of domestic crude production, 86 percent of domestic refinery capacity and 79 percent of domestic gasoline sales. The first four alone control over 50 percent of each of these operations. The majors own or have interest in 70 percent of interstate pipelines. They own or lease half the world's oil tanker tonnage. Until the recent nationalization moves, the seven international giants had held at least two-thirds of the world's proved reserves and production.

The vertically integrated nature of each of the major corporations is critical for the effective domination of the flow of its own oil from the well through the refinery and pipeline to its own service station pump. The ability to shift profits from one stage to another has been vital in driving out weaker refinery or marketing competition, maximizing advantage from import quotas when they were operative, avoiding or taking advantage of the tax laws of host nations and states, and generally masking the nature and profitability of their businesses.

This maneuverability has been pertinent to an understanding of the recent "energy crisis." Faced with greater demands for profits, production controls and participation in all phases of decisionmaking from the increasingly sophisticated producer nations, the international companies sought to increase their own profits downstream at the

refinery and marketing phases. At the same time they would be developing price floors for alternate energy sources under their control.

There is some competition among the international brotherhood of oil merchants for reserves and markets. But they also have a community of interest which is guarded through patents, banking ties, common capital underwriting firms, accounting services concentrated in a few firms, interlocking directorships through a third firm, bidding understandings in relation to public lands, recognized territorial prerogatives, crude oil and product exchange arrangements, regional price leadership and price fixing. Domestically, the majors operate much like a cartel. The industry is a private planning mechanism which has operated on an essentially global scale to shape the development and flow of the energy resources at the base of modern industrial life. The prime objectives are corporate growth and profit. In all its activities the industry seeks to maintain a delicate balance between supply and effective market demand. Vigilance against any abundance which might upset its pricing controls can never be slackened lest the nightmare of competition upset the private controls and planning timetable. The corporations know that popular usage of the term "reserves" is often misleading. "Proven reserves" applies not to any absolute geological limit as to what is in the ground, but rather to what is considered recoverable at the going market price, employing currently available technology.

From the perspective of the industry the regions of the world are a cluster of natural storage basins. Reserves are to be staked out, not developed, until there is no threat to the longrun control by the corporations from the expanded supply and the price is right. As the increased participation and nationalization moves began to sweep the producing areas, the oil corporations focused on maintaining their access to crude supplies and ensuring that the producer states respected the value of orderly marketing. Now the corporations are negotiating for the privilege of buying back royalty oil and generally keeping production in harmony with its global allocation while discouraging independent corporations or consumer nations from direct dealings with the producer nations.

New pipeline and refinery construction is appraised most cautiously to ensure the "orderly flow" of petroleum. There has been very limited refinery construction in the United States, despite the sharp increase in demand. Much of the self-celebrated industry investment went into overseas facilities where the markets and profits appeared more attractive. Just before the "energy crisis" of 1973, refinery runs in the United States were under capacity, despite the availability of sufficient crude and the abundant evidence of rising demand. This reflected the majors' resistance to government controls over the price of heating fuel oil, their concern over the vigor of independents, and their desire to strengthen price. Few of the economic patterns and events reflect the characteristics of a genuinely competitive industry. One may not have to prove conspiracy to see historic roots of the 1973 "energy crisis" and the patterns of collaboration of the presumably competing companies. When there is a miscalculation, as has happened before, or when there is an unpredicted curtailment, then the tightly wound mechanisms for the control of oil can easily lead to temporary consumer shortages.

The oil industry also controls much of the nation's natural gas. The integrated oil companies have over 70 percent of reserves and production. The industry is very unhappy with existing federal regulation at the wellhead of the price of natural gas sold in interstate commerce, even though gas prices in new fields have escalated under special regional and cost rulings of the Federal Power Commission. Industry talk of gas shortages has accelerated since 1968 when the Supreme Court and the Federal Power Commission rejected its arguments that rates were not producing new reserves and failed to grant the higher pricing sought. The issue is not present unprofitability but rather the expectation of greater profitability.

If oilmen rarely succumb to the periodic hysteria over petroleum's immediate disappearance, they are mindful that fossil fuels have ultimate limits and are essentially non-renewable. Alert to the interchangeability and potential threat of alternate fuels, the corporations have broadened their activities in coal, shale, tar sands, uranium and even the so-called non-conventional geothermal and solar sources.

They now view and often describe themselves as "total energy" corporations. Monopoly control over technically alternative fuels reduces the freedom of electric power companies, manufacturing industries, metallurgical processors and residential space heat users to choose from competing sources. Giant utilities find their options increasingly shaped by the private government of oil.

The United States Department of the Interior has jurisdiction and activities which touch upon a great many areas critical for the development and conservation of energy. Its functions have ranged from the gathering of basic energy information and the supervision over public lands to the administration of oil import policies and the stimulus of research for alternative fuels. With respect to the management of publicly-owned mineral resources, it is expected to assure the orderly and timely development of resources, protect the environment, and secure for the public a fair market resources on the disposition of such resources.

To a disturbing extent Interior's performance has been most consistently shaped over the years by the assumption that it is holding public lands (up to a third of the land area of the United States and the continental shelf) for disposal to private claimants. It has found itself uncomfortable in dealing with broad questions of public policy for energy. And conservation has often been, both historically and at present, an afterthought. Interior's working perspective has kept it a partner in development, responsive primarily to the private government which controls energy. It is an ineffectual guardian of the public domain and insensitive to the longrun public interest in the development, use and conservation of energy resources. In many respects it serves as the first line of defense of private industry, helping to keep profits secure, prices up, and private controls over energy insulated from public accountability. It remains beholden to the profit mechanism as the surest guide for the development and allocation of resources. As long as the government gets a percentage of the revenues from the leasing of public lands for oil and gas, few other questions are encouraged. For example, during the outcry over the oil blowout in the Santa Barbara Channel in 1969, it

became apparent that Interior had never developed the knowledge and the will to question the need or appraise the ecological implications of such drilling. Its primary public concern had been the revenue it obtained for the public treasury. Inadequate attention had been paid to the environmental risks that were being taken. Interior's Geological Survey appeared to operate without any apparent awareness of the conflict between its role as a promoter and celebrant of the frontier development of the outer continental shelf and its responsibilities as a regulatory body enforcing environmental standards.

Interior and industry have shared an interpretation of the public which excludes full disclosure of all the facts about leasing plans for the continental shelf, motives, timetables and alternatives; adequate time for participation by non-investing citizens, experts and environmentalists not on the corporate payroll; and meaningful coordination of planning at all stages of the exploration and leasing process with local, state and regional agencies. Interior's assumption that the community involvement criteria of the National Environmental Policy Act are met at the time of the drafting of environmental impact statements ignores the underlying decisions about energy development and leasing and the nomination of tracts made prior to such review. It excludes thoroughgoing analysis of the overall impact, including of the extensive onshore facilities which may accompany offshore operations, and the social changes and costs in the daily lives of the immediate populace. Such participation comes too late for any open exploration of the premises, objectives, alternatives and likely results of the national program for energy self-sufficiency and of the place for the specific plans for the outercontinental shelf in this framework. No questions are asked about precisely how the resources from these public lands will be placed into the overall operations of the private government of oil.

The actions of the Department of the Interior support the suspicion that environmental impact statements are pro forma. Similarly, the spirit and intent of the Coastal Zone Management Act calling for federal actions to be consistent with state plans are undercut, for the decision to lease offshore resources locks the state and local governments into programs which must accommodate the growth caused by what are seen as essential onshore oil and gas facilities to support the offshore drilling. Proclaimed urgencies of the energy

crisis" and of "national security" can thus serve as convenient escape hatches for the basic commitments for development already made before the communities are so informed. Meanwhile, the industry insists that the caution demanded in the leasing of the outer continental shelf is an "unwarranted overprotection of the environment."

The corporations have generally taken the lead in indicating the regions they want to see the Department open and they then suggest tracts which should be put up for leasing. Interior generally lacks adequate knowledge as to the extent and worth of the potential oil and gas. In place of careful and publicly accountable exploratory work its limited surveying resources have led it to rely extensively upon the geophysical data gathered by industry. To Interior the most reliable advance information "is what people are willing to lay on the line to pay for it."

Interior has lacked criteria, resources and incentives for thorough environmental impact studies and for the meticulous supervision of preliminary exploration, drilling and production, as well as for the examination of alternative energy policies and their relation to outer continental shelf drilling. Until prodded by critics, Interior seemed untroubled by joint ventures among the major corporations and by the complex interlocks of producers and pipeline systems. It has generally accepted a bonus rather than a royalty bidding system, although the former accelerates the concentration of control of offshore oil in the hands of the majors. Interior's lease management efforts have been quite modest. Inspections are often inadequate. It never fully investigates reasons given by the corporations for the shutting in of leases; it has been casual about renewal of leases which have not been producing.

Interior generally serves as an industry watchdog on Capitol Hill, testifying against any proposals which might upset its cozy junior partnership with the energy industry or chart independent energy policies for the nation. Some of the patterns of ignorance about the public domain relate to budgetary limits, some to the narrow technical background of industry personnel, and some to the limits of a bureaucratic system where the passive route - "we just work here" - is always the safest. Viewing energy as a commodity rather than as a resource and the industry rather than the public as its first client by now comes quite naturally to the department.

A revolving door tradition ensures a steady interchange of personnel between industry, industry-oriented universities, oil law firms and the government. All are carefully screened by the industry. Biographies of members of Interior's Oil and Gas Office continue to indicate that most have had oil ties.

The federal government is honeycombed by a network of energy advisory bodies composed of leaders of the major corporations and trade associations. These advisors define the acceptable bounds of policy alternatives, police their implementation and in effect become the makers of public policy. They thus undercut the legislative process and distort responsible administration. The access and the camaraderie of the oilmen in government, reinforced by the advisory system, result in control of information upon which decisions about resource development and use, rationing, price controls, inflation, taxes, foreign policy and literally war and peace are made.

In the absence of a clearcut overall national energy policy, related to an appropriate development plan and conservation ethic, there is only an illusion that the Department of the Interior acts as the agent and trustee for the larger public interest. Given the tremendous economic resources of the energy industry and the permeation of its influence throughout the body politic, such industrial self-government serves as another device for integrating economic and political power and for shielding decisions from congressional review and popular accountability and participation. In such a context, accelerated leasing of the outer continental shelf is not supportive of a responsible national policy. Instead it moves to lock up public lands which otherwise might be developed through genuine competition, fall under more stringent public controls or become part of a coherent public program for resource development and conservation. It serves to forestall the creation of a new public corporation for the stewardship of such public resources.

Oil and gas will not be produced for some years under the present policies. But public options will be narrowed considerably if corporate greed is once more given first priority in the name of Consumer need. Accelerated leasing of the outer continental shelf will make it more difficult for such a public agency, left with the

less desirable public lands, to serve as a yardstick experiment for providing the public with adequate and fairly priced energy which is not developed at the expense of the generations yet to be born.

This affidavit is developed more fully by the author in his report THE OIL, INDUSTRY, THE DEPARTMENT OF THE INTERIOR AND PUBLIC POLICY FOR ENERGY prepared in 1974 for the Nassau-Suffolk Regional Planning Board. He is also author of THE POLITICS OF OIL, A STUDY OF PRIVATE POWER AND DEMOCRATIC DIRECTIONS published by Macmillan (1961) and the University of Chicago (Phoenix edition, 1967). Robert Engler testifies frequently on matters of resource and energy policy before congressional and other public bodies. He is currently professor of political science at the City University of New York. He holds a doctorate in political science from the University of Wisconsin.

Sworn to before me this
19th day of July 1976.

Robert Engler
Robert Engler

James C. [unclear]
Notary Public

My Commission Expires
Nov. 22, 1978



UNITED STATES DISTRICT COURT
EASTERN DISTRICT OF NEW YORK

-----X
COUNTY OF SUFFOLK, COUNTY OF NASSAU, TOWN
OF ISLIP, TOWN OF HEMPSTEAD, TOWN OF NORTH
HEMPSTEAD, TOWN OF OYSTER BAY, TOWN OF
HUNTINGTON and the BOARD OF TRUSTEES OF
THE TOWN OF HUNTINGTON,

: Civil Action
: No. 75 C 208

: Plaintiffs

: -against-

: AFFIDAVIT

: SECRETARY OF THE INTERIOR and CURTIS J.
: BERKLUND, individually and as Director
: of the Bureau of Land Management

: Defendants.

-----X
STATE OF NEW YORK)

: SS.:

COUNTY OF NEW YORK)

FRED DUBIN, being duly sworn, deposes and says:

I am the President of Dubin-Mindell-Bloome Associates, P.C., Consulting Engineers, having our principal office at 42 West 39th Street, New York, New York. My professional qualifications are attached as Exhibit 1.

I submit this affidavit in support of the plaintiffs' request for a preliminary injunction enjoining the Secretary of the Interior from holding lease sale 40 in the Mid-Atlantic on August 17, 1976.

I have reviewed the following documents issued by the United States Department of the Interior:

1. Final Environmental Statement for proposed increase in oil and gas leasing on the Outer Continental Shelf - FES 75, Vols. 1, 2 and 3, prepared by the Bureau of Land Management - in particular those portions concerning the alleged need for OCS drilling, alternatives to offshore drilling in the areas of energy conservation and solar energy.

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2. Final Environmental Statement for proposed 1976 Outer Continental Shelf oil and gas lease sale 40, the Mid-Atlantic States, Vols. 1, 2 and 3 - in particular those portions dealing with the subject of alleged need and the alternatives of energy conservation and solar energy.

In my opinion, for the reasons hereinafter stated, the Bureau of Land Management has not made an adequate evaluation of the need for offshore drilling and the alternatives of energy conservation and solar energy.

FINAL PROGRAM ENVIRONMENTAL STATEMENT

Volume 2, page 283 states,

"The potential for new oil and gas through OCS is stated to be approximately three million barrels of oil per day and 12 billion cubic feet of natural gas per day. This amounts to approximately ten quadrillion BTU's per year, but it is unlikely that the leasing schedule would include the total recoverable resources of OCS."

On page 284 it is noted,

"Any source which can produce or conserve approximately ten quads per year can be considered as an alternative to the proposal."

These sources could be one, or a combination of many, and it further states that conservation of a quad is equivalent to production of a quad.

The latter statement is questionable because the production of a quad does not take into account the amount of energy required to produce that quad. Thus the net energy produced would be less than the quad saved by conservation.

Pages 295 through 301 are devoted to a discussion on "energy conservation". They note that the Ford Foundation report, the Project Independence blueprint, and Environmental Protection

Agency indicate a potential savings through conservation of 7.40 to 8.53 quads per year in 1985 savings in fossil fuels of even the most optimistic projection of energy supply of OCS production in this period. It is reported that the conservation opportunities, if adopted, could save the equivalent amount of energy that would be supplied through OCS production through 1985.

However, the references quoted were not based on specific studies for the New England-Middle Atlantic region and were not in any manner a complete and detailed analysis of the potential of conservation and the cost to implement. The potential is far greater than that presented in those references. Neither Volume 1 nor 2 outlines a method of further qualifying and quantifying the "energy conservation option".

On page 327 of Volume 2, a general discussion of solar energy as an alternative is presented.

However, the discussion on solar energy ends on page 331 and does not go into any detail, nor does it consider the real potential for solar energy, given the rapid strides which have been made in the past 18 months on hardware and total systems. Furthermore, there is no discussion of the real cost of comparing solar energy with offshore drilling. The gross costs for the offshore oil alternative, including exploration, drilling, and the energy required for extraction are not addressed at all, and the BLM does not present a comprehensive economic and engineering analysis of the two alternatives.

Pages 477 through 524 contain a discussion of potential conservation measures describing requirements to implement them. I would concur that all of these are valid and would make

a significant impact upon energy demand if implemented. However, the measures which are described are far from a sufficient assessment of the potential for conservation which is substantially greater than that stated. Furthermore, the impact of the ASHRAE 90-75 standards, referred to on page 694, which will reduce energy consumption, has not been addressed at all in these volumes.

My analysis of the three volumes of the final program environmental statement leads me to conclude that they lack the detailed energy conservation analysis needed if the Department of the Interior is to answer the question whether OCS drilling is necessary, or whether energy conservation is a preferred alternative.

The scope of a meaningful energy conservation study should include the following:

A. The analysis of end use of fuel and energy in buildings in the New England and Mid-Atlantic area by building type and subsystems. Energy use questionnaires should be sent out to 1,000-2,000 buildings with the object of gathering data on unit energy consumption (kwa/sq.ft., gals. of oil/sq.ft, etc.) for various types of buildings. The energy forecast reports of every electric and gas utility in the included states should then be reviewed to obtain exact methodologies and data (both consumption and peak load) used in projections.

B. The quantity and use of all imported oil for each state in this region should be traced with the object of determining the areas of consumption that would be most desirable to be supplied by offshore oil, and how they will grow in the future.

C. A forecast of energy requirements from 1976 to 1995 should be made. It would be based on "normal conditions" taking into account, price, industrial and commercial activity, demographic projections, energy conservation standards for buildings and appliances which are now being promulgated by the states and other communities, as well as heat pumps and other energy conserving equipment which are emerging and becoming commercially available, and other related factors. To make this forecast, demographic studies by planning agencies in the included states should be analyzed with the object of determining the future population, number of single and multi-family housing units, commercial employment and economic activity, industrial employment, school student population, hospital beds, government jobs, construction programs, and any other related data. This should be done for each state. The goal would be to generate floor area and plant projections from the data. Department of Commerce reports on energy use for different fuel types for each state for each end use category should also be reviewed. This would involve an assessment of industrial, commercial, governmental, and residential fuel usage.

D. An estimate should be made as to the decrease in energy consumption which would result from an energy conservation program beyond the level currently employed in new and existing buildings. ECM-1 and ECM-2 and the GSA energy conservation guidelines could be used to identify and quantify energy conservation measures in buildings and industrial processes.

E. An analysis should be made of the decrease in consumption of fuels which could result from a major penetration of solar energy for heating, hot water, cooling, industrial processes, using off the shelf hardware which is now available and

which could be cost effective. It would then be possible to calculate the savings on a region-wide basis using solar energy for heating, hot water, cooling, and process heat using designs being developed under a HUD grant program. Other solar energy analyses in this region should also be evaluated.

F. The study should also take into account the new emerging solar energy technologies which are predicted to be on line in the next ten years.

G. Estimates should also be made of the savings in fuel made possible by utilizing solid waste, onsite power generation with total energy systems, peaking cycle, and bottoming cycles.

H. The potential for wind energy to reduce fuel consumption in the area should also be studied.

I. The type of study proposed would take approximately 18 to 36 months. It is only through such a study that the Bureau of Land Management can realistically indicate the potential through the energy conservation and solar energy alternatives for reducing oil, gas, coal and electrical consumption in the New England and Middle Atlantic region. Without such a study, the Bureau of Land Management cannot truly say that it has adequately evaluated the alternatives of energy conservation and solar energy.

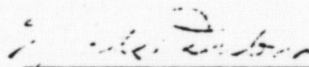
FINAL ENVIRONMENTAL STATEMENT
OCS SALE NO. 40

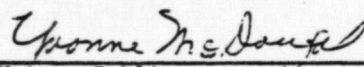
I have also reviewed the references to energy conservation or solar energy in the final environmental statement for lease sale 40. I have found no information therein which amplifies the discussion of these subjects contained in the

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final program environmental statement. Hence, in my opinion, the site specific environmental statement for sale 40 is also inadequate insofar as its discussion of these alternatives. My analysis of the final environmental statement for sale 40 reinforces my opinion as to the need for a detailed energy conservation analysis and its impact on fuels and resources for the Mid- Atlantic and New England regions.

Sworn to before me this
16th day of July 1976.


Fred Dubin


Notary Public

YVONNE McDOUGAL
Notary Public, State of New York
No. 30-2513865
Qualified in Nassau County
Commission Expires March 30, 1977

10 February 1976



Mr. Irving Like
Counsellor at Law
200 West Main Street
Babylon, New York 11702

Dear Irving:

As a result of discussions between you and some of our faculty members yesterday we promised to reduce to writing our comments on the BLM environmental impact statement on proposed lease sale no. 40, and answers to certain questions raised by you. Present at the meeting, besides yourself, were J. R. Schubel, P. K. Weyl, H. B. O'Connors, M. J. Bowman, C. D. Hardy, and J. L. McHugh.

The environmental impact statement appears to have been put together in a hurry and to have received inadequate review. Even if the scientific aspects had been covered adequately, however, the statement would have been deficient, for it is our unanimous opinion that it addresses the wrong questions. It is unlikely that decisions as to whether to lease or not can be made from consideration of the environmental issues alone. As far as the living resources are concerned, it will be extremely difficult to predict, or to assess in "real time," the impact of exploration or exploitation on the living resources. Furthermore, we question whether the capacity to predict or to assess damage would be very much improved after five years of research or even longer.

For the area from approximately the Gulf of Maine to Cape Hatteras we already have fairly good estimates of the magnitude of the living resources and their capacity to sustain a total harvest. Most essential details of the life history of the major species and their distributions and migrations are already known. This information has provided the basis for concluding rational fishery management arrangements with other nations. Fluctuations in abundance of individual species and stocks from natural causes are large enough, so that, aside from catastrophic events, it would be extremely unlikely if not impossible to measure or predict the chronic effects of energy-related activities on the living resources. However, chronic effects of energy-related activities on the biota generally in coastal environments are not well documented or understood. For example, recent investigations on the impacts

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of an oil spill near Nova Scotia, Canada, showed that oil particles may be ingested by zooplankton. The effects upon zooplankton mortality, growth rate, and fecundity are not known. Well conceived laboratory studies, coupled with a complementary field sampling program could aid in documentation and understanding of the chronic effects of continental shelf oil production.

As far as ocean circulation is concerned the flow over the outer continental shelf is complex and highly variable. But it is well established that the mean flow is from north to south along the shelf. With increasing distance from shore it becomes increasingly unlikely that an oil spill over the shelf would reach shore.

For these reasons, it would appear much more productive to question the present need for assessing or developing petroleum reserves in this region. The magnitude of the petroleum resource is speculative, and the economic feasibility of extraction therefore is undetermined. We suggest that a useful way to resolve the deadlock would be to require adequate exploration and assessment of petroleum reserves in the area to provide a basis for economic evaluation. This also would provide a means for evaluating potential gains from petroleum development against potential losses from interference with other uses of the environment. No definitive means of comparing economic values now exists.

Exploration obviously must precede exploitation, and we think that decisions to exploit should be postponed until the resource has been explored and evaluated. Exploration would best be done by government, directly or under contract.

Rigid standards of methodology and procedure should be developed as a basis for making informed decisions on whether to lease or not. The present environmental impact statement does not provide such standards.

As information develops from exploratory operations, which might include further assessment of living resources and laboratory research on effects of petroleum fractions on various life history stages, standards of operation should be drawn up for the exploitation phase. These should include strict operating procedures and methods of surveillance and enforcement. Criteria should be included for terminating leases in the event of failure to observe well defined and strict standards of operation or occurrence of unexpected events that might violate

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established environmental standards. Equally stringent controls should be placed on construction and operational procedures associated with transport of petroleum products to shore, to avoid environmental damage.

The two rough charts or "decision trees" attached illustrate our concepts of the present decision making system and the system as it ought to be. The way in which decisions are currently made is outlined in figure 1. The crucial leasing decision is made by government at the very beginning, before adequate assessment of the resources and the environmental and social impacts can be made. After this, decision making is done by industry based on economic factors that largely exclude environmental and social costs. Instead we recommend the procedure outlined in figure 2. The crucial cost benefit analysis is made by government after the exploration phase. At this point, expected benefits from discovered resources can be weighed against environmental and social impacts. Additional site specific environmental information has been gathered during the exploration phase. Social impacts can be evaluated only after the size of the resource and its nature (oil and gas or both) has been ascertained. At this stage realistic input from State Coastal Zone Planning becomes possible.

In summary, we believe that the realistic way to approach the lease sale issue would be to use present knowledge of environmental conditions and environmental uses to establish decision criteria. Adequate exploratory evaluation should precede exploitation. The decision to exploit should be based on results of exploratory drilling, and should include consideration of future energy needs and the economics of the energy system as a whole. Criteria for decision making, at each step in the process, should be sufficiently clear so that there should be no reasonable doubt whether to proceed to the next stage of development, or not to proceed.

I hope these comments will be helpful.

Yours sincerely,

J. R. Schubel

J. R. Schubel
Director

OCS DECISION TREE PRESENT SYSTEM

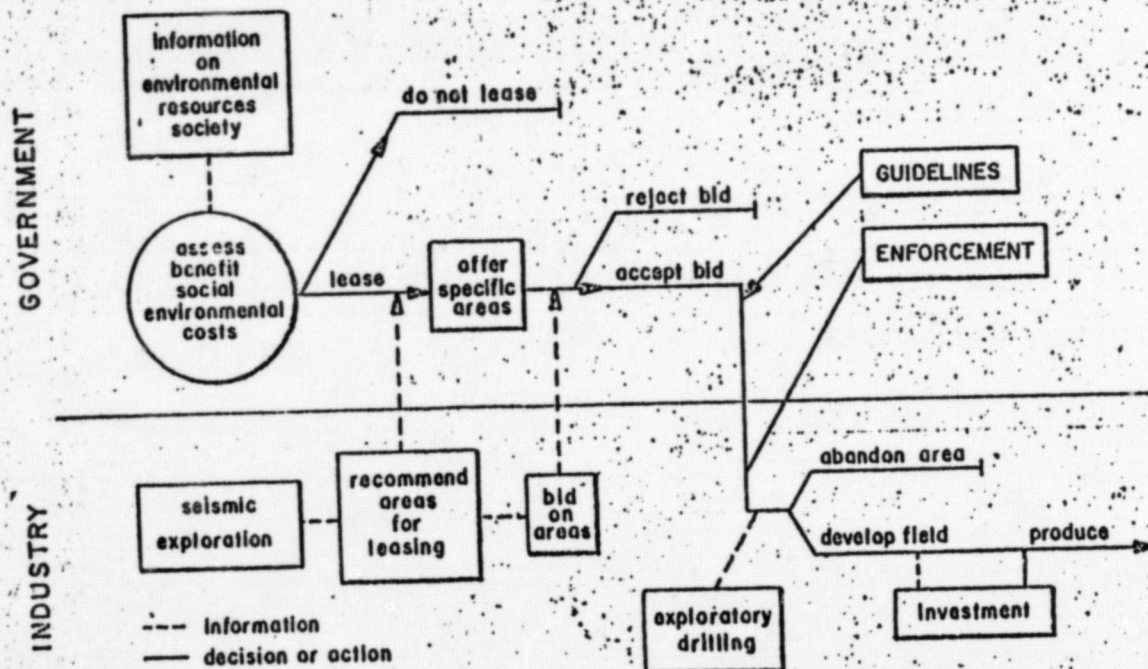


Fig 1

OCS DECISION TREE RECOMMENDED

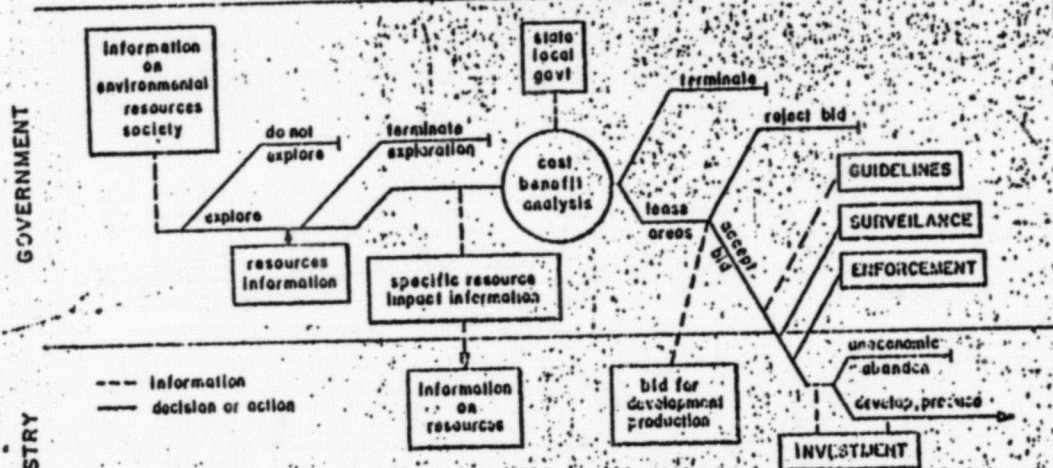


Fig 2

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CRITIQUE OF THE U.S. INTERIOR DEPARTMENT'S PROGRAM-
MATIC PROGRAM DECISION OPTION DOCUMENT
ON THE OUTER CONTINENTAL SHELF ACCELERATED LEASING
PROGRAM (September 1975)

by Christopher T. Rand

A strong case can be made that in at least five respects the September 1975 Program Decision Option Document (PDOD) on the Accelerated Leasing Program in the Outer Continental Shelf, by the U.S. Department of the Interior and its Office of OCS Program Coordination uses poorly-supported arguments to justify increased leasing of federal offshore lands which one may refute by abundant evidence, evidence available to the U.S. Department of the Interior, and indeed often by statements within the PDOD itself. One might summarize these five arguments as follows:

- I. The contention that foreign sources of energy (for all intents and purposes liquid hydrocarbons) are unreliable or "insecure." (This argument underlies Project Independence, initiated March 1974.)

- II. The claim that it is a powerful foreign cartel, the Organization of Petroleum Exporting Countries (OPEC), which is responsible for the current high world-wide energy prices -- as well as the insecurity.
- III. The corollary contention that alternate sources of liquid and gaseous hydrocarbons (oil and natural gas) -- outside OPEC and the U.S. outer continental shelf -- are not, and will not become, available to American consumers in sufficient quantities and that the U.S. consumer therefore has little but the latter two sources to turn to for his supplies.
- IV. A lack of concern about the price which the consumer has to pay for energy, coupled with the assumption, strongly implied, that the abundant alternate sources of energy which do exist (including known fields on federal lands) are more costly to develop and operate than outer continental shelf lands yet to be leased, and that the proper price for energy should be the price at which energy from these unleased lands can be brought to market at a profit.
- V. The assumption that the existing procedure by which the U.S. Department of the Interior leases out federal lands for energy development, and existing rules governing this procedure -- in particular the bonus bidding system -- constitute

the most effective way to remedy America's "energy problem" underlying points I-IV.

A set of questions to be presented to the Department of the Interior, falling under each of these five categories, will follow this critique. Together with explanations on the relevance of these questions, they will help County of Suffolk et al. press their claim against the Department of the Interior's campaign to lease out federal lands on the mid-Atlantic outer continental shelf. The rebuttal to the five above categories of argument, which proceeds as follows, can assist as a sort of strategy outline for the use of these questions.

I. The underlying justification for the leasing of further land on the United States outer continental shelf is that this land contains the deposits of oil and gas without which America will become more and more the victim of foreign energy suppliers in coming years. The PDOD claims that energy imports are "insecure" (p. 2), and goes on to state: "During the 1973 Mideast War the Arab oil producers imposed an embargo on shipments of oil to the U.S. and certain other countries. This occurrence demonstrated [emphasis supplied] the vulnerability of the U.S. to interruptions in imported petroleum supply." The PDOD uses this claim to justify President Nixon's 1974 call for domestic energy independence and the subsequent cumbersome, expensive efforts to launch Project Independence, whose attainment is still the goal of President Ford, despite

much criticism, even from oil companies themselves. On p. 13, the PDOD contends, "Increased OCS production of oil and natural gas would reduce our dependence on foreign oil imports.... which are insecure sources of supply," and states, on p. 26, "If a decision is made not to proceed with accelerated leasing, the economic benefits of... secure oil supply from the OCS will not be realized."

The PDOD makes no effort, however, to show to what extent foreign oil supplies are unreliable and the United States is dependent on, and vulnerable to, these sources. It offers no consideration whatever of the scope, effectiveness or nature of the Arab embargo on oil exports to the United States or any other country. Moreover, it makes no attempt to review serious essays at explaining the high cost which keeping foreign oil out of America in the past has entailed.

The most important of these studies, perhaps, was the February 1970 Report by the Cabinet Task Force on Oil Import Control, with its majority recommendation to President Nixon that the oil import controls in existence at that time (and indeed until April 1973) be rescinded. Among the arguments which the report made were that the imports program was costing the U S. economy \$4 to \$5 billion a year; that the threat of Arab embargo was in some ways insignificant and that the national security could be protected even if additional imports were brought into the U.S.; and that if the import quota system were abolished, the prices of crude oil and refined

products in the country would drop substantially -- even if a tariff of \$1.45 were imposed on each barrel imported.

Such omissions are particularly glaring in a study as influential as the PDOD, especially since much evidence has accumulated in the last two years that the 1973-74 Arab oil embargo was not nearly as severe as Nixon Administration officials claimed and that this administration shelved the Task Force's recommendations for over three years, not for reasons of security or economy but under pressure from domestic oil interests, largely through the agency of Senator Russell Long's Finance Committee. Such omissions help indicate that it is the Interior Department's aim to lease land and obtain cash bonuses totalling hundreds of millions of dollars, rather than to promote an exhaustive national energy debate leading to the formulation of comprehensive domestic energy policy.

The PDOD also fails to discriminate between different foreign energy sources -- let alone various sources within OPEC. Though it dismisses foreign sources with the adjective "insecure," the PDOD makes no mention of the producibility of known fields or the potential of other prospects in non-Arab oil sources within OPEC -- especially Iran, Indonesia and Nigeria -- though information on this is available to some extent to other U.S. government agencies (such as the State Department and the CIA). Nor does the PDOD contemplate the producibility and potential of Libya or Iraq, militant Arab states which nonetheless increased their exports during the 1973-74

embargo. The omission of Iran, in particular, is significant: development there was hobbled to the benefit of Saudi Arabia in 1964-75, on the basis of cost, not security; the companies operating in those two states were more concerned with costs than with the relative security of the two sources. The Shah's offer to the State Department, in late 1969, to provide America with a strategic oil reserve is but one instance which shows that foreign sources are far more diverse and willing to cooperate with the United States than the Department of the Interior realizes, or declares.

II. In extension of this point, the PDOD proceeds from the assumption that OPEC constitutes a powerful cartel which is singlehandedly responsible for the current high costs of energy, as well as insecurity of supply, throughout the world. On p. 3 it declares, "During and after the Arab oil embargo, the OPEC cartel rapidly raised the price of oil. World prices rose as high as \$20 per barrel at one time. Lately prices have been stabilized at around \$11-\$12 per barrel, and supported at that level through production cutbacks among the cartel members."

Though it is true that the world price did rise to \$20 very briefly and has been stabilized at \$11-\$12 since early 1974, in most (though not all) exporting countries, it is by no means certain that mere OPEC production cutbacks are responsible for that or that OPEC could constitute a "cartel"; it is an unwieldy organization of thirteen nations spanning the

globe, some rich in oil, others relatively unendowed with resources, each saddled with its own set of economic and social problems, whose members, as we have recently seen, cannot even agree to punish the kidnappers who victimized them. Even among the Arab bloc within this bloc, there have been lengthy acrimonious struggles. There is considerable evidence, which the U.S. Department of the Interior is beholden to solicit and weigh, that the high prices are, rather, the result of distribution and market-sharing agreements between the seven major oil companies (five of which, Exxon, Mobil, Gulf, Standard of California and Texaco, are American) which in the aggregate lift off 90 percent of OPEC's oil by contractual arrangement which the OPEC states cannot break -- though they have, on paper, bought out the greater part of the concessions these seven used to hold on their territories.

This market-sharing pattern has persisted almost fifty years, has been studied off and on by the U.S. Department of Justice and congressional investigators, and has been concealed, off and on, by the major oil companies, with the connivance of U.S. government officials. Yet it is extremely relevant here, because it is precisely the seven major international firms which will develop a dominant position in the lands which the Interior Department intends to lease on the continental shelf, if Interior follows its past leasing procedures (which, according to the PDOD, it will).

At several points, the PDOD half-heartedly speculates

on the "possibility that circumstances might change.... This might happen if the value [sic] of oil fell because OPEC collapsed" (p. 20), offers alternate scenarios "if OPEC is expected to collapse within three years [that is, by late 1978] or not at all" (p. 30), and surmises that "our expectations about future oil and gas prices... may also change" (p. 38). However, the PDOD does not state whether it would be desirable for the price to drop or for OPEC to "collapse," or at least lose some of its sting; indeed, as we shall see, the PDOD strongly implies that Interior considers high prices desirable. The PDOD does not state, either, whether Interior has pursued, contemplated pursuing, or has been offered an opportunity -- directly or indirectly through any other U.S. government body (such as the State Department or CIA), by any foreign state inside or outside OPEC, to contemplate pursuing a policy of providing the United States with secure foreign energy supplies or of helping to weaken OPEC's influence on world market prices.

III. As a corollary to Rint II, the PDOD is totally inadequate in buttressing its claim that viable alternate sources of oil and natural gas are not available to the American public -- outside OPEC or the unleased OCS lands. There are, in fact, energy sources, both outside the U.S. and on federal lands already under lease within the U.S., which have the potential to satisfy enough of America's energy deficit to make

it futile to worry about that small portion of oil which would still have to be imported from the Near East were this nation to forego pursuing the prohibitively¹ expensive Project Independence to the hilt.

The most obvious -- but by no means sole -- foreign source of crude oil which could directly or indirectly add to the security of U.S. supply lies, at present, in the North Sea. The PDOD admits that "In the North Sea, for example, an average of 1 exploratory hole per 250,000 acres available resulted in 10 billion barrels of discovered reserves." Again, the Department of the Interior has a public responsibility to buttress statements of this type with firm data or, lacking data, to relegate them to the domain of pure conjecture, but it does neither. It is probable that the thirty oil-bearing structures discovered so far in the British and Norwegian sectors of the North Sea contain three times as much oil as this, or 30 billion barrels of recoverable reserves. A field in that area, even to be considered for development, would have to contain at least half a billion barrels of recoverable oil to be commercial, and several fields, such as Forties, Hutton, Piper, Ninnian, Brent and Ekofisk, contain several times that.

The PDOD offers no comment whatever on the producibility or potential of properties already discovered on U.S. government land, whether these be in the Alaskan North Slope, California's outer continental shelf, Naval Petroleum Reserves 1 and 4, the outer continental shelf of Louisiana, or federal

lands in New Mexico and the Rocky Mountain areas of Colorado, Utah, Wyoming, and Montana. Conflicting statements have been published on petroleum properties in these areas over the years. To give one example, while some experts consider that Exxon's Santa Ynez unit in the Santa Barbara Channel has reserves of 1 to 4 billion recoverable barrels, the Interior Department keeps its information on the subject confidential and the American Petroleum Institute includes only one of the Santa Ynez structures in its list of important American reserves, assigning it a potential of only 90 million barrels. (The Oil and Gas Journal of August 26, 1974 explained that "Exxon does not disclose its own estimate of producible reserves.")

Thus, one is compelled to ask the Department of the Interior to show irrefutable proof that existing known resources on U S government land cannot provide the "increased production of 3 mbd of oil and 12 bcf of natural gas a day" which the PDOD, quoting an Environmental Impact Statement, claims could be obtained from the millions of acres of OCS land it intends to lease. Conversely, and perhaps better, one could force the Interior Department to provide, in regard to all these public lands, geological data which ^{on} study by competent independent geologists and petroleum engineers (not necessarily U.S. citizens), would most likely reveal that the American public has a far greater inventory of oil and gas than hitherto generally believed. (For instance, studies by congress-

ional investigators and sources within the Federal Power Commission have come up with strong evidence that the oil industry has underreported its natural gas reserves in offshore Louisiana by 40 percent and that the Department of the Interior has uncritically accepted the industry's data.)

Moreover, in an era when much talk is circulating about exotic and very costly methods of generating further energy by coal gasification, conversion of sewage to methane, and liquefaction of oil shale, the PDOD offers no speculation about massive heavy oil reservoirs which the U.S. Department of the Interior has described in detail in unclassified documents.

There are other areas where oil companies have succeeded in preventing or delaying the development of alternate energy transportation systems, in particular oil pipelines, to offer consumers greater access to oil supplies. In this connection one need only mention the Alyeska and Iran-Turkey pipelines, though there have been others. It is certain that construction of the former, first projected in 1969 but not due for completion until mid-1977, was seriously delayed not only by environmental groups but also by Standard Oil of California and Exxon. There is much circumstantial evidence, and some documents, to support this claim; in fact, one of the nation's most prominent environmental activists once admitted to me, when I told him this, that opposition to this project by groups with which he was affiliated had been a mistake, at least in the manner in which it was carried out.

The same holds for the Iran-Turkey pipeline, which has yet to be constructed. Both Iran and Turkey had contemplated building it for decades but the major oil companies evinced interest in it only on occasion, as a weapon for scaring the Arabs (as it would send Iranian oil to the West by skirting the Arab world); all Iran and Turkey wanted from the companies, however, was a commitment that they would ship a certain volume of oil through the line, since they would use this commitment to finance it themselves and operate it as a common carrier yielding negligible profit. It is likely that the Department of the Interior -- again directly, or indirectly, through another U.S. government body, such as the State Department or the CIA -- had considerable knowledge of the history of these two pipelines and may have played a role, albeit passively, in preventing their timely construction.

IV. The PDOD is extremely vague on present and future costs of finding, developing, and producing oil reserves on federal and other lands in the United States. To be sure, it does not unequivocally call for any price higher than the levels of \$3 a barrel or 20 cents an MCF which prevailed for oil and gas 5 years ago in this country. However, it very strongly implies that the potential production on unleased outer continental shelf lands will be less costly than the alternate sources of oil available to the American consumer, and it conveys the impression (which it has been Interior Department

policy to do, throughout the Nixon and Ford Administrations) that the prices the American consumer paid for various forms of energy until late 1973 were extremely, indeed excessively, low.

First, the PDOD, as we have seen, speaks critically of foreign oil, on grounds that it is costly as well as insecure. Then it leads one to believe that offshore oil production is not very expensive (which is undoubtedly true): "The costs of OCS oil have been variously estimated to range from \$1.00 to \$7 a barrel [exclusive of transfer payments such as bonuses]" (p. 4). "Department of Interior estimates indicate that the best million acres of OCS land in various frontier areas could produce oil for \$1-2.50 per barrel" (pp. 4-5). "Substantial production appears attainable for an average cost below \$7 per barrel" (p. 5). "Foreign oil imports, which are more costly than OCS production..." (p. 13).

Yet while the PDOD states that new OCS leases will offer lower cost oil, it will not call for markedly lower prices. Rather, to the extent that it endorses any price level at all, it seems to be calling for prices sufficiently high to make production of oil from OCS lands profitable for those firms which are able to pay the massive bonuses for which the Department of the Interior is leasing the lands. (One must not forget, incidentally, that this arrangement is not so profitable for the government: companies write the bonuses off at 20 percent a year (or 100 percent for accounting purposes), and, if they abandon the leases, gain a writeoff of 100 percent in the

year of abandonment. This will become clearer in the next section.) Thus, to Interior, the desirable price for OCS oil appears to be not the lowest attainable price, but the lowest which would make the leasing of new OCS lands by bonus bidding attractive to those firms able to pay the bonus.

To give this claim some justification, the PDOD reasons, dimly, on pp. 7-10, that alternate sources of domestic energy cannot be had in volume for less than \$8.50 a barrel; below a cost of \$8.50 a barrel, coal and nuclear energy could not replace much oil; shale and coal liquefaction could not make inroads on oil below \$8-11 a barrel; secondary or tertiary recovery of oil could not occur below \$9-11 a barrel. (Again, the PDOD neglects the massive reserves of oil, recoverable by conventional means, which exist on federal lands already leased or under development.) The PDOD does seem to make some exception for natural gas. It has been a long-term objective of the oil industry, the Nixon and Ford Administrations, and Interior to raise the price of gas far above its current federally-controlled levels, and thus also far above its cost. Thus the PDOD implies (p. 11, footnote) that the production cost of this fuel might not be the same as the "true value" of natural gas, which would make this a truly exceptional fuel.

There is very strong evidence — almost overwhelming, in fact — that the average total costs of finding a barrel of oil in the United States and getting it out of the ground and into a refinery have remained quite constant at around \$2.

This figure was valid in early 1973 and has hardly changed, in spite of the drastic increases in price worldwide. Nor, indeed, has the drastic increase in the margin of profit from producing oil led to increases in America's oil output. This does not mean that America cannot increase its oil production; it could just as well mean that it is in the interest of a number of large companies to maintain the existing balance between expensive imports and low-cost domestic production. Many firms, in particular the major U.S. five, have large volumes of foreign oil for which they can find no place except in the United States.

The PDOD has not offered concrete estimates of the volumes of foreign oil which production from unleased OCS lands might replace. It has not provided any estimates of the volumes of oil from known properties in the United States or reliable sources abroad on which the United States could rely -- under ordinary circumstances or in cases of emergency. On top of that it has not offered any conjecture about the profits companies might earn by producing from unleased OCS lands. The third point has serious implications for the structure of the energy industry in America, as well as the equitable distribution of the national wealth. Therefore the Department of the Interior, if it wishes to press the leasing of offshore mid-Atlantic lands, is obligated to give the public as much data as it can acquire on the costs of exploring for, finding, developing and producing oil from known deposits on federal

lands so that the public can draw its own conclusions -- again, with the aid of independent experts -- on the costs, profitability, and thus the reasonable pricing of oil and gas produced from these lands. This entails acquiring, from the Department of the Interior, cost data on known fields and prospects in Alaska's North Slope, the California OCS, Naval Petroleum Reserves 1 and 4, offshore Louisiana, and federal lands in New Mexico and the Rocky Mountain areas. It is essential to demand that Interior provide this data on a company-by-company, zone-by-zone, field-by-field basis. This, in conjunction with the other two points noted at the beginning of this paragraph, should enable the complainants to form an excellent picture of the amount of low-cost oil and gas yet to be produced on federal lands in the United States, and thus to draw up a powerful case for postponing the leasing of further offshore lands. It is even possible that Interior might postpone the leases rather than divulge detailed cost and reserves information on federal lands throughout the U.S.

Corollary to this, it is essential also to obtain information, again on a company-by-company, zone-by-zone, field-by-field basis, regarding the development costs of U.S. reservoirs of heavy crude oil (oil of 25° API gravity or less). Published Department of the Interior documents assess recoverable reserves of this oil at 5.2 to 106.8 billion barrels (the range depends on the market price of energy in general). This may enable the complainants to obtain an even fuller picture of

the low-cost oil reserves yet to be developed in this nation before recourse need be made to ~~unleased~~ federal lands.

V. In seeking to solve the nation's ill-specified "energy supply problems," the PDOD considers but fails to support or advocate any method for leasing out federal lands which might compete with the existing bonus bidding system. Here, too, the PDOD's arguments are inconsistent, poorly thought-out and at odds with the broader public interest.

These arguments fall into several categories: a comparison of the merits of bonus and royalty leasing; the extent to which states may influence the course of OCS lease development; the role of the government in exploring for and producing oil and gas on federal lands; the role of the American public in the development of OCS leases; and the extent to which cost and reserves data bearing on public lands should be made available to the public.

Regarding the comparative merits of bonus and royalty bidding, it is clear that bonus bidding benefits large companies where the tracts to be offered are offshore areas requiring large capital investments yet entailing low operating costs. Royalty bidding, on the other hand, would clearly benefit smaller concerns. A small, aggressive firm with little cash cannot afford to pay big bonuses in advance, but it may be very willing to pay big royalties as it earns money from production, sacrificing large immediate profits for the opportunity to acquire a larger share of the market. The PDOD fails

to take this elementary consideration into account. What it does say is that royalty bidding might in the long run turn out to be more expensive for the companies. It states, "the OCS leasing program appears to have significant net benefits at this time" (p. 31), then refers to the October 1974 royalty experiment (p. 49) and contends "when downstream [sic; this should probably be "deferred"] lease payments are increased, there is a higher probability that leases will not produce [than when all payments, except the 16 2/3 percent royalty, are made at the outset] " and "the transfer of revenues to the government [through higher royalties].... can preclude development on otherwise economic leases."

This argument is academic, in a sense, because major companies, such as Shell, boycotted the October 1974 royalty bidding experiment, thus dooming it to failure, at least in the eyes of the Department of the Interior. (Major firms are, however, willing to bid on a royalty system onshore if they have to to win rights to acreage of high promise.) But if royalty leasing is more expensive to the companies than bonus bidding, the bonus bidding system is therefore more advantageous to the companies -- hence more of a giveaway. If the bonus bidding system is adopted because a number of large firms prefer it to the royalty system, it then confers on them a form of representation without taxation, because the government is not getting all the money it possibly can from its leases. It is true that oil companies have paid upwards of

\$100 million, by certified check, for individual leases. However, this does not represent a hardship for them, as they have the money to begin with, which smaller firms do not. Then, on top of that, if a company subsequently abandons the lease it can reclaim half the bonus at once -- that is, it can deduct the bonus as an abandonment from its federal income tax liability, which is 50 percent of taxable income. If it keeps the property it can reclaim half the bonus in equal instalments over five years. If they get nothing else from the leases, the major firms at least gain the right to keep them from falling into the hands of smaller, hungrier companies which might well be more anxious to produce from them.

This point is specially relevant to the mid-Atlantic offshore areas. If these lands prove productive they will be closer than any other energy source on earth to a major energy-poor industrial megalopolis. Thus they will confer even greater leverage on those who possess them. The PDOD makes it apparent that the Department of the Interior has no intention of conferring them on small, hungry, cash-poor companies. "It is reasonable" to continue the present bonus-bidding system, it writes, "if front-end costs and development risks are not judged to be a problem" (p. 49). These costs will not be a problem to the major firms, and it should be possible to ascertain that the mid-Atlantic is a low-risk area to boot.

The PDOD offers little control over the development of OCS leases to states off which these leases lie; the recent

history of energy development in California offers examples of this. The PDOD, while claiming that Interior is drawing up "proposed regulations" so that states may have a chance to "comment upon" OCS development plans, admits that once the decision is made to develop OCS lands, the states cannot stop it: "granting a state a right to review development plans can never result in a denial of development rights" (p. 40). Even the contention that states can hold up development (pp. 29-30) may be an empty one, since big companies are likely to apply considerable pressure, with success, to hasten Interior's approval of development plans.

Interior's policy toward the states matches its distinction between the government and the public; on p. 41, it considers it fitting that the government should require information on OCS leases, and that steps "can be taken to increase information available to the government," but goes on to state, "geological information is required to be submitted to USGS, but this data is never made public by USGS." The PDOD does mention a "proposed change" which would make geological data on leases available to the public in six months, and geophysical data within ten years. But this would be of little use to the public since it would only apply to land which had already been leased.

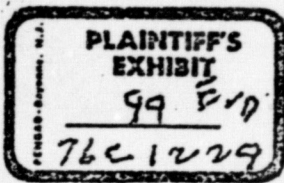
According to the PDOD, in fact, even the government itself is to remain impotent in developing federal lands. The document considers, then rejects, the notion that the government

might engage in offshore exploration through a federal oil and gas company, by refusing to consider the alternative that government might act as only one of several companies developing the lands. The PDOD writes, "There are substantial risks of inefficiency or even ineffectiveness in the exploration program" if exploration were to be left to government: "Thus a policy of government exploration of the OCS.... would likely reduce and delay the discovery of oil and gas on the OCS" (p. 39). Most advocates of a federal oil and gas company, however, are not seeking a government monopoly of energy development, but rather a benchmark company in competition with established firms which can add to the "large number of explorers" which the PDOD itself calls for!

Thus, the objective of the Department of the Interior, as expressed through the PDOD under review here, is to keep the government and the public out of the development of the outer continental shelf and to keep the major oil companies dominant in this development, at a low price. However, it is the comprehensive access to data on oil and gas inventories and on the costs of adding to and cultivating these inventories which enable oil companies, particularly the major ones, to maintain their hold over the world's energy resources. The companies, and their partisans, place much emphasis on the high cost of energy development and the sophisticated hardware and technical expertise which these companies must maintain

in order to keep the world supplied with low-cost energy, but it is, in fact, these companies' power over information, often intangible -- sometimes even locked in the minds of mid- and lower-level executives -- which enables them to continue dominating the business of supplying the world with energy. Evidence exists that major companies know how much money they will have to spend to enlarge their inventories by given amounts. Strong evidence has also come to light in recent years that companies have access to one another's so-called proprietary data, allow one another such access, and perhaps even share it. (There is at least one document in the possession of the U.S. government which proves this.)

Therefore, it is on the subject of the confidentiality of data, and the degree to which different types of industry data should remain proprietary, that the PDOD -- and government energy policy in general -- are, and have consistently been, the most deficient and vulnerable. The U.S. Department of the Interior -- and indeed all government energy agencies, certainly since the advent of the Nixon Administration -- have pursued a policy of protecting this confidentiality, making no effort to entertain a debate with the public on drawing up and policing the borderline between equitable withholding of data and the protection of data (especially that data which, while withheld from the public, is readily accessible within the industry). Thus it is on this ground, as outlined in the preceding five points, that the complainant's most effective challenge to the mid-Atlantic leasing program lies.



February 11, 1976

Bureau of Land Management
New York Outer Continental Shelf Office
6 World Trade Center
Suite 600-D
New York, N.Y. 10048

Gentlemen:

I am special counsel to the County of Suffolk which opposes the proposed oil and gas lease sale (OCS #40) for the Mid-Atlantic Coast in the Baltimore Canyon trough.

I respectfully forward herein the following:

1. Critique of the U.S. Interior Department's Programmatic Program Decision Option Document on the Outer Continental Shelf Accelerated Leasing Program (September 1975) by Christopher T. Rand
2. Letter and 2 diagrams from Prof. Jerry R. Schubel addressed to Irving Like, dated February 10, 1976

Suffolk County Executive John V.N. Klein is forwarding to you under separate cover his statement in opposition to the proposed sale.

I respectfully request that these documents be incorporated into the record of the hearings on this proposed sale and that they be given due consideration as required under the National Environmental Policy Act.

Very truly yours

Irving Like

IL:mc
Encs.

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3032

**Summary Of
An Interim Report To The
Technology Assessment Board**

**COASTAL EFFECTS
OF OFFSHORE ENERGY
DEVELOPMENT:
OIL AND GAS SYSTEMS**
Prepared By

**The Office of Technology Assessment
Ocean Assessment Program**

March 16, 1976

The Interior Department has not delegated full-time responsibility for all of its OCS programs to one office despite a demonstrated need for improved coordination of OCS-related activities both within Interior and among Interior, other Federal agencies and the States.

Despite the urgency which the Administration attaches to expanding offshore lease sales and petroleum production, the Interior Department has no full-time, policy-level coordinator with line responsibility for Outer Continental Shelf operations. As of March 1976, no such consolidation of responsibility and accountability for OCS programs was contemplated.

In addition, clear lines of responsibility for OCS operations have not been established between Interior officials and officials of the Office of Coastal Zone Management, despite the fact that offshore development in the Mid-Atlantic and other "frontier areas" could produce the most important impacts on coastal zones of any single new development since the Coastal Zone Act became law in 1972.

Line responsibility for OCS activities is divided within the Interior Department between two bureaus -- the U.S. Geological Survey (USGS) and the Bureau of Land Management (BLM) -- both of which have a wide range of other activities that overshadow their OCS responsibilities in terms of manpower and budget.

During the 14 months ending January 1976, the Assistant Secretary for Program Development and Budget, Royston S. Hughes, was responsible for coordination of OCS activities at the Interior

Department. It was an assignment in addition to his other responsibilities of managing the Department budget, supervising policy planning and analysis, conducting economic analyses of Department programs and dealing with environmental and natural resource policy issues. He was supported by a three-member staff headed by a Director of the Office of OCS Program Coordination. Officials in New Jersey and Delaware and at the Interior Department told an OTA researcher that the departure of Hughes from Interior disrupted progress toward opening lines of communications through which substantive issues could be argued to a conclusion. State officials also said that their relationship with Hughes was informal and personal. Thus, the lines of communication depend on the man and his position, not on the way in which Interior was organized to deal with the States.

Since January 1976, the policy level coordinating job at Interior has been vacant. The staff coordinating job has been vacant since September 1975, despite the fact that the program to lease tracts off the Mid-Atlantic coast has moved through several crucial phases during that period, including publication of the Mid-Atlantic draft Environmental Impact Statement (EIS). The task of OCS coordination has been assumed by the Director of Policy Analysis as a part of that office's Department-wide duties.

A plan for appointing a full-time OCS coordinator was completed in early 1976 for consideration by the Secretary of the Interior.

In general, it called for the Assistant Secretary for Program Development and Budget to continue sharing OCS coordination with his other responsibilities. In addition, the plan called for a full-time OCS director who would report to the Assistant Secretary. The office would be responsible for analyzing OCS policies, assuring the participation of States in decisions, resolving differences among Interior officials who have line responsibility for offshore oil development and coordinating studies involving OCS activities.

Congressional Options.

A. Assign to a single policy-level office within the Department of the Interior the authority and responsibility for OCS policy coordination, without making any changes in lines of authority.

B. Assign to a single policy-level office within the Department of the Interior land use, ocean use, economic, geologic and other planners who now work independently in various sections of the Interior Department with OCS responsibilities. Delegate to that office not only responsibility for general program coordination but specific line authority and responsibility for:

--those sections of the U.S. Geological Survey which now draft and enforce regulations for offshore oil and gas activities;

--those sections of the Bureau of Land Management which now supervise offshore leasing and environmental studies programs.

New Jersey and Delaware officials believe that they are not receiving adequate information on which to base plans for dealing with the onshore impacts of offshore development. Under present laws, regulations and procedures they have no guarantee that all of the information they believe they need for planning will be provided by either the Federal government or the oil industry.

The flow of information from the Federal government to the States since the 1974 decision to accelerate offshore leasing has been slow and uncoordinated. State officials say they are concerned about the flow because they need comprehensive and timely information in order to plan for coastal effects of offshore development.

Offshore energy development eventually may require construction of staging areas, pipelines, tank farms, gas processing plants, and perhaps even new refineries to support OCS oil and gas production. State officials say they are concerned that onshore activities may require major investments of public funds that necessitate considerable advance warning and some assurance not only that the investments actually are required but that OCS-related revenues ultimately will support the expenditures. For example, Delaware officials say that there is presently a lag of eight years between planning and completion of a major highway in the State.

State officials say, by and large, that they appreciate the fact that there are limits to the Interior Department's ability to provide some types of data. What concerns them, they say, is that the confusion that exists now in exchange of data will

not be clarified by the time their needs for hard data become more than academic.

After management plans have been approved by Federal officials under the Coastal Zone Management Act, both States presumably would have a legal right under the Act to "necessary information and data" about any Federal activity in their coastal zone, including activity related to offshore oil and natural gas development. However, the Act does not specify whether the States or the Federal government would interpret the word "necessary," which raises doubts that it will solve the States' information problems.

Regulations on development plans require the industry to provide certain information to the States and officials at Interior are now asking the States what information they believe should be included in development plans. But there is no description in law or regulations that specifies the information to which States are entitled in development plans or related impact statements.

Congressional Options.

A. Additional information could be required for inclusion in industry plans and in supplements to standard development plans. This information could include:

- quantity and location of the resources discovered;
- complete description of the oil and gas production system, including platforms, gathering lines, pumping facilities, separation equipment and pipelines;
- all operating procedures, including environmental and health safeguards and how these will be maintained;

--a detailed analysis of site-specific environmental conditions for the offshore areas where platforms will be located to produce oil and gas discoveries, and in the nearshore and offshore areas which will be crossed by pipelines; and

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--a detailed description of the size, required land, and personnel and proposed sites for each onshore facility, including pipeline corridors, staging areas, supply boat docks, tank farms, gas processing plants, and transportation plans for all elements of the operation.

B. An Environmental Impact Statement could be required as a supplement to development plans. The EIS could incorporate all data gathered after preparation of a draft EIS, and throughout the exploratory phase, as well as data to be gathered once industry formulated site-specific development plans. Included in this information could be:

--shallow geologic and oceanographic descriptions, including sediment behavior, and identification of hazardous areas;

--biologic descriptions, including identification of sensitive areas;

--meteorological information; and

--information on other ocean uses in the area.

The EIS, which could be prepared jointly by the Federal agency and the affected States, could compare various alternative locations for each type of onshore and nearshore facility (including pipeline corridors) in terms of environmental and other consequences, and

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evaluate each set of alternatives with regard to consistency with the State's coastal zone management plan, or comparable statements of state planning objectives for the coastal zone

Issue: State Access to OCS Decisions.

Top officials in New Jersey and Delaware say they do not believe that current laws and practices for planning and administering offshore petroleum development allow for adequate State involvement in important decisions. Lacking more direct involvement in decisions, State officials say they may try to block or delay implementation of decisions with which they disagree.

State officials have been concerned that such crucial decisions as sale of leases, enforcement plans and — until recently — review of development plans have been made unilaterally by the Federal government even though all three decisions influence the eventual onshore impacts of OCS development. Lease sales, for example, set in motion a development process that can rarely be slowed or stopped under existing laws and regulations. The first development plan is the base on which decisions are made incrementally about locations of pipeline landfalls, staging areas and tank farms. Enforcement plans have a direct bearing on the care that will be exercised in drilling and production and an indirect bearing on the quantities of oil likely to be spilled offshore. This lack of State participation in early decisions has helped create an adversary relationship in which a State's only option for controlling onshore impacts may be to obstruct the process, thus bringing about the very kinds of delay in OCS development that the Federal government wants to avoid.

A policy goal could be to create a framework for relationships between State and Federal governments that would insure States full participation in major OCS decisions. One way to assure State involvement in those major decisions could be to make such involvement a legal right of a State rather than an option of Federal decision makers. The right of States to a voice in policy decisions that have potential consequences for their citizens, economic or environmental, could be guaranteed up to, but not including, the right to veto Federal offshore development plans.

States already have the right through their riparian laws, environmental protection regulations and zoning powers to block or delay development once it involves State lands. However, State officials say they would prefer involvement in the planning process to exercising a veto in later stages of development.

Under S. 521, a revision of the OCS Lands Act of 1953, which has been approved by the Senate, States would be entitled to comment on development plans before they were approved by a Secretary of the Interior, to have written explanations for a Secretary's rejection of any of those comments, and to appeal such rejections to the U.S. Circuit Court of Appeals.

Congressional Options.

A. Congress could consider applying that same principle of arbitration to other important decision points in the development process. For example, it could require the Interior Department to

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environment. Some of the programs also include other specific biological, oceanographic, geologic and meteorologic studies.

The purpose of these studies has not been fully defined, and it is not clear how the information developed can or will be used in the decision-making process of leasing OCS lands and managing or regulating subsequent OCS activities. Presumably, the environmental studies will begin to establish a definition of the "baseline" or existing environmental conditions against which environmental impacts that may be caused by any oil and gas activities throughout the life of an offshore field can be measured. The studies also would continue in conjunction with oil development and used in monitoring of any environmental changes. Many biologists believe that such studies also should be used to identify environmentally sensitive areas or special hazards that would indicate which areas, if any, should be withdrawn from lease offerings.

The lack of a clear relationship between environmental studies and the OCS decision-making process, however, is a principal issue. If there is little or no relationship between the studies and management decisions, then the value of the investment in them is questionable. If the studies do not include environmentally sensitive regions such as nearshore waters or do not provide adequate scientific evidence, then the value of the results are questionable.



3012

State of New Jersey
DEPARTMENT OF THE PUBLIC ADVOCATE
DIVISION OF PUBLIC INTEREST ADVOCACY
P. O. BOX 141
TRENTON, NEW JERSEY 08601

STANLEY C. VAN NESS
PUBLIC ADVOCATE

ARTHUR PENN
DIRECTOR
TEL. 609-292-1892

December 16, 1976

Honorable William F. Hyland
Attorney General for New Jersey
State House Annex
Trenton, New Jersey 08625

Dear Attorney General:

The Department of the Public Advocate represents several New Jersey counties as Amicus Curiae in the case entitled Natural Resource Defense Council v. Thomas S. Kleppe, Secretary of the Interior in the Federal District Court for the Eastern District of New York. This case involves the role of off-shore leases for the exploration and possible development of oil and gas resources. For preparation of our case, certain information is needed.

We are given to understand that although New Jersey has title to the submerged lands between the commissioner's line (1,000 yards out) and the three mile limit, that there is no authority that exists at this point or that has been created by the legislature which would permit the alienation or conveyance of any lands between the commissioner's line and the three mile limit for purposes of construction of a pipeline or other off-shore facility. Please advise me if this is the case, at your very earliest convenience. If this is not true, please indicate what authority to make a conveyance or an alienation does exist.

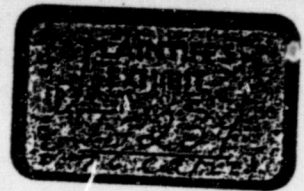
Thanking you for your cooperation.

Very truly yours,

ROBERT P. CORMAN
Assistant Deputy Public Advocate

RPC/db

3013



State of New Jersey
DEPARTMENT OF LAW AND PUBLIC SAFETY
OFFICE OF THE ATTORNEY GENERAL
STATE HOUSE ANNEX
TRENTON 08625

WILLIAM F. HYLAND
ATTORNEY GENERAL

ROBERT P. MARTINEZ
SPECIAL ASSISTANT
TO THE ATTORNEY GENERAL

January 5, 1977

Robert P. Corman, Esq.
Assistant Deputy Public Advocate
Department of the Public Advocate
P.O. Box 141
Trenton, New Jersey

Dear Mr. Corman:

Although we have issued no formal opinion on the subject, this office has taken the position that additional legislation would be necessary in order to authorize the State to convey an interest, however limited, in lands beyond the bulkhead line out to the three mile limit.

Sincerely,

WILLIAM F. HYLAND
Attorney General

BY:

Roger M. Schwarz
Roger M. Schwarz
Deputy Attorney General

RMS:fm

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TESTIMONY OF FREEHOLDER DARYL F. TODD

ATLANTIC COUNTY, NEW JERSEY

ON PROPOSED OUTER CONTINENTAL SHELF LEASE SALE

January 28, 1976

SHERATON-DEAUVILLE HOTEL AND MOTOR INN

ATLANTIC CITY, NEW JERSEY

I am pleased to have this opportunity to testify this morning on behalf of the legislative body of Atlantic Counties government, our Board of Chosen Freeholders. -

I appear as Chairman of the Off-Shore Development Control Committee which has primary responsibility at the local legislative level for maintaining and developing local county policy with respect to all areas of off-shore development including the dumping of sludge in our waters, the possible construction of floating nuclear power plants and the exploration and development for oil and natural gas.

You have heard many witnesses before me and I am aware that there are many to follow. Therefore, I will spare you the ordeal of hearing me dazzle you with my ability to quote verbatim from the Draft Environmental Statement.

I read with some amusement the four page set of instructions on the procedure to be followed at these hearings and the request that we direct our testimony to the leasing actions specifically with respect to individual tracts rather than to leasing generally. I say with some amusement because I do not have access to any specific information with respect to the individual tract. Who does have such specific information? I assume

the oil companies do because the Atlantic Seal and Gulf Seal have been searching for oil out of our Atlantic City Harbor since at least 1969. These ships were employed by a reported consortium of some 49 to 52 oil companies. So it really becomes ~~asham~~ ^{ashame} to expect us to comment specifically when we do not have access to certain available information. I noted with dismay that Representative William Hughes of this congressional district had to invoke the Freedom of Information Act against the Department of the Interior in order to get the identification of 20 oil firms seeking leases in the Atlantic Ocean. In this enlightened area of supposed open government, it does shock the sensibilities to realize that the elected representative of people has to use a legal blackjack to obtain information from the appointed representatives of the people.

Well, since I found that I was not able to comment specifically on the tracts, I then said to myself, well perhaps I can comment on the lease because we are talking about a leasing arrangement. So I looked in the Draft Environmental Statement for the lease form itself and I searched in vain. If it is there it escaped my search.

Let me explain to you some of my concerns on behalf of the citizens of Atlantic County. Those like me who were reared on Long Beach Island in Ocean County just north of here in the late 40's and early 50's remember vividly the can of kerosene always kept by the back door during the

which might be experienced. This fund should in no way be used as a substitute for the concept of unlimited liability for losses caused to our local environment and economy. A combination of private insurance, self insurance and government protection should be utilized if necessary. If economic and environmental damage to our area is a cost of doing the nations business to meet energy demands, then that cost should be shared nationally and not just here.

2. There should be a provision for revenue sharing with the State of New Jersey who then should pass these funds along to the counties and municipalities effected by the development on-shore. Some studies seem to indicate that the State of Louisiana in 1972 suffered a 38 million dollar loss when comparing the revenue from off-shore drilling compared with the cost of providing services caused by it. A similar study in the fall of 1974 projected a loss of Texas of 62 million for the same reason. Surely we should learn from these experiences and provide fair and equitable revenue sharing for the State of New Jersey and Atlantic County.

3. There should be preparation of environmental and economic impact statements after the amount of off-shore oil and natural gas has been determined by exploration. These impact statements would be prepared at the expense of the oil and gas companies doing that exploration and developing.

It seems to me that this Draft Environmental Statement is just so much wasted paper at this time because the nature and extent of the oil and gas reserves in the Baltimore Canyon are not known at this time. With respect to oil, in 1975 studies seem to indicate there were 12 billion barrels. Newsweek Magazine reported up to 14 billion barrels. The Woodward-Clyde study for the American Petroleum Institute approximated 6 billion barrels and Mr. Manning of Amoco Oil was reported in the Journal of Commerce to have said there may be up to 40 billion barrels. The U. S. Geological Survey estimates 2-4 billion barrels. So we see a range from 2-40 billion barrels. Surely the environmental effects from one end of the scale to the other are dramatic.

The situation with respect to natural gas is the same. The U. S. Geological Survey estimated 5-16 trillion cubic feet. The Woodward-Clyde Report estimated 32 trillion cubic feet. Newsweek reported up to 266 trillion cubic feet and another report I saw indicated 167 trillion cubic feet.

The answer is simply that we must have a better handle on what is out there before we go running off giving leases to develop it. Which leads to another position of this county.

4. There should be a separation of exploration leases from development leases so that the federal government will not give away our federal natural resources before the quantity of that resource is known. Your own goals indicate and the law requires the receipt of a fair return for the leased mineral resources. Before we know what is out there how do we know that 16% is a fair royalty. The government should pay the cost to private industry for exploration and have available to it all of the information with respect to the nature and extent of our natural resource before bidding away development leases.

5. There should be a requirement that the off-shore oil and natural gas discovered in the Baltimore Canyon area be sold domestically and not to foreign markets. If this cannot be accomplished by legislation, then surely it should be inserted in the leases. A lease is nothing more than a contract between parties and surely the government can drive a harder bargain with our oil and gas companies to require that this new resource be sold domestically. The whole reason for this development of the Baltimore Canyon is to help meet this nations energy needs and therefore to require domestic selling merely carries out that national policy. We should attempt to make our independence from foreign oil a reality rather than merely talk about it.

6. There should be restrictions barring refineries and tank farms along the coast or in any community which does

not want them in order to protect our local quality of life. I realize that many say that the refineries will not be necessary in South Jersey. However, I find that hard to accept before we know the nature and extent of the natural resource off our coast. We in South Jersey will work for stringent application of our own State Coastal Area Facilities Review Act. (CAFRA). But beyond that the leases that I referred to earlier should also contain agreements by the oil companies not to seek refineries and tank farms along the coast of Atlantic County or along any other county that does not want it or in any community that does not approve it.

7. The federal government has seen fit to write into certain contracts requirements of minority hiring which has come to be known as the "Philadelphia Plan." We ask that the leases as written contain a requirement for an "Atlantic County Plan" which would require a certain substantial percentage of local hiring. This county will work with the federal government and private industry to provide a trained work force for proper utilization of our own Atlantic County Vocational School and other educational institutions. Our Atlantic County economy deserves no less for being subject to the problems which may occur as a result of this off-shore exploration and development.

The Atlantic County Board of Chosen Freeholders at his meeting yesterday adopted a position by Resolution which I have covered in most part in these remarks. I will attach

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a copy of that Resolution to my remarks for insertion
in the record.

Thank you for your indulgence.

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RESPONSE
OF
OCEAN COUNTY BOARD OF CHOSEN FREEHOLDERS
TO
DRAFT ENVIRONMENTAL STATEMENT
FOR
PROPOSED 1976 OUTER CONTINENTAL SHELF SALE No. 40
BY THE
U.S. DEPARTMENT OF INTERIOR

PRESENTED BY
ERNEST A. BUHR, DIRECTOR
OCEAN COUNTY BOARD OF CHOSEN FREEHOLDERS
OCEAN COUNTY, NEW JERSEY
TOMS RIVER, NEW JERSEY 08753

JANUARY 29, 1976

PROPOSED MID-ATLANTIC O.C.S. OIL AND GAS LEASE SALE #40 PUBLIC HEARING
SHERATON-DEAUVILLE HOTEL AND MOTOR INN
ATLANTIC CITY, NEW JERSEY

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OCEAN COUNTY BOARD OF CHOSEN FREEHOLDERS

RESPONSE TO

DRAFT ENVIRONMENTAL STATEMENT

for

1976 Outer Continental Shelf Sale No. 40

by the

U.S. Department of Interior

The Ocean County Board of Freeholders is gravely concerned with the prospects of leasing, drilling, and development of the Outer Continental Shelf and the impact that this would have on the coastal and marine environment of Ocean County and the State of New Jersey. On August 20, 1975 the U.S. Bureau of Land Management announced that a tentative list of 154 tracts totalling 876,750 acres was available for a proposed sale and that a multidisciplinary team of environmental and other specialists would begin preparation of a Draft Environmental Impact Statement. The resultant statement has served to heighten our concerns and to raise significant questions which must be addressed.

1. Ocean County is primarily a shore-oriented resort county whose resort/tourist trade facilities represent an investment of more than \$1 billion dollars and which generate hundreds of millions of dollars in trade, taxes, and income. According to the Statement's analysis of the tourism industry along the mid-Atlantic coast, however, revenues generated by this industry are regarded almost insignificantly. Such a conclusion is not surprising when the methodology used to calculate annual tourism revenues is considered. The study group utilized the fallacious tactic of omitting expenditures by visitors traveling less than 100 miles to the County. Constructing a 100 mile radius from Toms River, visits from persons throughout the entire State of New

Jersey, the five boroughs of New York, parts of Westchester County, eastern Pennsylvania, and half of the State of Delaware are summarily excluded. The assumption of the U.S. Data Travel Center, which prepared the methodology, was that "the cumulative economic significance of short distance day trips is minimal in the context of the remainder of the tourism activity". Coney Island would be a ghost amusement park if similar assumptions and arguments were used to calculate its economic significance. A single one-half mile beach and amusement area in Ocean County generates more than \$1 million in revenue. Millions of day-trip visitors who flock to the New Jersey beaches are ignored by the draft statement. This single point is reason enough to require an extensive reevaluation of the Draft Statment but it is only one reason. There are numerous other important points.

2. The Statement fails to adequately address the combined impacts of the proposed New Jersey off-shore sludge dumping program under consideration by the U.S. Environmental Protection Agency, the off-shore nuclear plant proposals for Southern Ocean County, proposed deep water ports along the northern portion of the County, and the heavily utilized shipping lanes which exist immediately to the north of the tentatively proposed tracts. Any combination of two or more of these developments could produce a dramatic alteration of the environment and pattern of land use in the County. We are particularly concerned that there does not appear to be any coordination between these programs. The O.C.S. leasing and drilling program cannot be viewed as an autonomous action.

3. The statement includes a series of maps in which Visual #1, Lease Status, Recreation and Open Space Resources, and Potential Hazards shows undetonated explosives dump sites that appear to be within parts of nine tracts nominated for leasing. Approximately 30 miles southeast of this site, a significantly larger area is used as a dumping site for both explosives and chemical wastes. While the Statement asserts that scientific procedures are available to pinpoint

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the precise locations of unexploded ordnance, it also asserts that "sea water may have defused the explosive capability of ordnance on the sea floor". This possibility is of little comfort to the County in being assured of the maximum safety of work crews in this area.

4. It is impossible to gain a clear perspective on the magnitude of the leasing program and its effects due to the wide range of possibilities on which the impact statement is based. Average daily oil production from the 154 tracts could run from 43,000 to 285,000 barrels per day utilizing 10 to 50 off-shore platforms. There may be anywhere from 200 to 880 wells which introduce 215,900 to 949,960 tons of bottom mud to the marine environment. Similarly, oil residue may stimulate the growth of vegetation and then again it may destroy all existing vegetation. Until the range of possibilities is more accurately delineated, we cannot hope to fully evaluate the leasing proposal. Environmentally the report indicates practically no impact to severe impact. Which end of the spectrum is closest to reality?

5. The Impact Statement contains a lengthy discourse on the probabilities of oil spills, pipeline leaks, and blow outs and it assures the reader that, while these accidents do happen, the volume of oil spilled is anticipated to be minimal. At the same time, however, nearshore spills during spring and summer will have the greatest adverse impacts on the marine environment and nearshore spills from pipelines would be most likely to occur along the New Jersey coast. While commercial fishermen may lose some 250 acres of fishing grounds along the Continental Shelf due to displacement by drilling rigs and sport fishermen may lose fishing opportunities due to oil tainting and outright destruction of fish, the public desiring to use the beaches of Ocean County may one day find itself dialing a toll-free number to ascertain seashore oil conditions, much in the manner as today's winter skier does for snow conditions. Under such circumstances, off-shore oil leasing and drilling is totally unacceptable to Ocean County and its extensive

resort/tourist industry.

6. The 154 tracts initially nominated represent only a small portion of the tracts which can conceivably be offered for leasing. Section VIII of the Statement outlines alternatives to the proposed sale including the substitution of other tracts nearshore and further off-shore than the previously nominated tracts. Tracts in the nearshore area include the entire coastal area from southern Monmouth County south to Cape Charles, Virginia and extending from 3 to 48 miles from shore. This alternative suggests the possibility of drilling rigs visible from the shore and the effective displacement of all recreation-oriented activities which, according to the Impact Statement, presently make up 90% of the beach-front land uses. Should petroleum resources be discovered in this area, nearshore operations may prove less expensive because of shorter pipelines and the reduced need for self-sufficient rigs far out at sea. We have no assurance that nearshore leasing will not occur at some later date. The environmental and economic tradeoffs required to implement this alternative are not acceptable. The nearshore alternative should be evaluated in greater depth to alert the resort/tourist trade of the potential destruction of the coastal recreation trade. We respectfully submit that such an analysis be made by an independent agency which is not tied to the actual leasing program.

7. One of the most disturbing aspects of the impact statement is its insistence on drawing conclusions and assumptions without the data to support them. The entire document is replete with statements as "the effects are not well understood" or "are unknown". It is totally unrealistic and simply unfair to suggest that the Department of Interior be held responsible for the enormous lack of data in the field of environmental science. It is equally unrealistic and unfair, however, to expect the public to accept, without question, the conclusions of an impact statement based upon this admitted lack of data. The statement is biased and at times it appears that the Statement is attempting to justify a decision to

drill on the Outer Continental Shelf of the Mid-Atlantic region.

Conclusions and Recommendations

While the Ocean County Board of Freeholders recognizes the national need to examine all alternative forms for increased energy, we do feel there are grave risks and hazards inherently associated with major commercial exploitation of petroleum and natural gas from the Atlantic Outer Continental Shelf zone. The Draft Environmental Statement does not fulfill the need for a systematic, interdisciplinary analysis toward insuring the integrated use of the natural and social sciences in any planning and decision-making which will have an impact on the environment. We strongly recommend that any further action on the sale of oil leases on the Continental Shelf be held in abeyance until a major revision of the Impact Statement is undertaken which will address the issues which have been raised. We do not believe that the Department of Interior should encourage the development of one natural resource which could effectively destroy or severely damage another. Until impartial assurance can be made about Sale No. 40, we strongly urge no further action be taken on the leases and we strongly urge that the Draft Environmental Statement, as prepared, not be accepted.

OUTER CONTINENTAL SHELF
BUREAU OF LAND MANAGEMENT STATEMENT OF
CAPE MAY COUNTY BOARD OF CHOSEN FREEHOLDERS
AND CAPE MAY COUNTY PLANNING BOARD

My name is William Diller. I am Chairman of the Cape May County Planning Board and represent the Cape May County Board of Chosen Freeholders and the Cape May County Planning Board. We thank you in advance for the opportunity of appearing in response to your solicitation of public comment on the policy of accelerated Outer Continental Shelf development.

Cape May County is a unique area. Cape May County is primarily and essentially, in an economic sense, a resort-recreation area. In fact, we are the "recreational backyard" of the Northeast Megalopolis. More than 90 percent of the County's economy is attributable to the resort industry. That industry is our economic base, grosses more than \$185 million dollars annually and generates a cash flow in excess of \$400 million dollars. The resort industry has grown at a compound annual rate of 8½ percent for the last 9 years and is not brought to its knees by cyclical periods of inflation and recession as are industrially based economies. Our economic base is inextricably bound to a high quality natural environment and barring man-made overdevelopment or Outer Continental Shelf induced industrial development, the growth potential for the resort economy is virtually unbounded in time and unlimited in gross dollar value. It is the long term goal of County and municipalities of Cape May County to remain in the resort-recreation business.

If and when oil is located in the Baltimore Canyon, that quantity of oil will be finite. Temporarily withholding judgement of the broad policy question, I can say unequivocally that after oil is pumped, refined, sold and burned and the drilling rigs move on to new locations, Cape May County intends to still be primarily and essentially in the resort-recreation business.

With that point of view established, we respond as follows to your request for comment on the policy question of accelerated Outer Continental Shelf leasing.

In general, the system for solicitation of public response is cumbersome and inadequate because the policy question must be resolved before the detailed impacts at specific drilling areas are enumerated in the Environmental Impact Statements for those lease-sale areas. In other words, a "go" decision must be made before the facts come out.

Further, we find the time allotted for public review of the draft EIS prior to the public hearing to be totally inadequate.

Having established an elementary economic profile of Cape May County and recognizing the constraints imposed by the inadequacies of the review process, we offer the following comments on the EIS and policy question.

The landside impacts of Outer Continental Shelf development promise to be swift, irrevocable and potentially devastating to coastal resort areas. While we commend and applaud the efforts

of the Interior Department (and other agencies) to regulate, administer and control the environmental impacts at Outer Continental Shelf drilling sites, efforts to minimize on-shore, so-called secondary impacts, should be pursued aggressively. In looking toward the sea, the Interior Department has turned its back on the land.

In the absence of a detailed EIS regarding the Baltimore Canyon and Cape May County area, many land use questions remain. Refinery and petrochemical complexes are unsited. Locations of storage and supply facilities are unknown.

Cape May County recognizes the national need for oil. National needs and the County's needs are not mutually exclusive. We also recognize the needs of our citizens and the long term goals of our county and in light of these, the Cape May County Board of Chosen Freeholders and Planning Board adamantly oppose the policy of accelerated Outer Continental Shelf development.

To wit, much of the scenic beauty of coastal Scotland and England has been swiftly and irrevocably destroyed by the continuing development of offshore drilling in the North Sea.

The small fishing village of 24 people, called Drumbuie, on the rugged north coast of Scotland is a poignant example. This region is considered by many to be the most beautiful in the United Kingdom with forested mountains and rocky shoreline deeply etched with tidal lochs comparable to Norwegian fjords. The village of Drumbuie in concert with the National Trust for Scotland objected when the oil companies wanted to use this area to build the twenty story rigs they use for off-

for Scotland, and local people formed the Southwest Ross Action Group to stop the project. The Trust's fight was supported by donations from Scotland, Europe and abroad. A public inquiry sat for 43 days hearing the evidence and in August, the British government ruled that "Environmental considerations were conclusive" in its decision to preserve Drumbuie from industrial development. We hope the United States government will do at least as much for Cape May County.

In light of the fact that the 10 million acre lease-sale in one year is equal to all of the acreage-of-lease-sales since the Federal Government leased the first tract 20 years ago, the accompanying landside impacts are overwhelming. Stringent land use planning must precede development. The federal government should not sell lease tracts and ignore the consequences.

The EIS appears to neglect discussion of the logistics and manpower problems associated with the proposed quantum increase of accelerated leasing, particularly in the area of offshore inspectors (technicians and engineers). If staffing problems do exist in administrative or field inspection areas, the acreage of lease-sales should be reduced as opposed to leasing projected acreage with inadequate inspection.

As previously stated, Cape May County is a unique area. It is the "recreational backyard" of the Eastern seaboard. More than three million tourists visit Cape May County each year. Attracting those

tourists is a direct function of the areas high quality natural environment, clean air, clean water and unspoiled land. Cape May County is a major flyway for migrating birds in their semi-annual coastal passage; the value of our bays and wetlands to the food chain that ends with man cannot be measured. The County is one of the few remaining areas in the populous Northeast that has not been ravaged by urban sprawl. The living environment of Cape May County cannot be matched elsewhere and, once destroyed, can never be recreated by man.

While landside effects are our primary concern, offshore water quality impacts still rank high. The economic and environmental consequences of a major oil spill which you classify as inevitable, would be devastating.

We have read the studies and statements of the Department of Commerce relative to the Tanker Construction Program and its potential impact on our County.

We have read the Arthur D. Little Study projecting gross onshore industrial development in our County induced by deepwater port construction.

We have read the Interior Department's Environmental Impact Statement on deepwater port landside impacts on our County, with its description of an oil spill off the coast of Delaware impacting the entire New Jersey coast with 2 billion dollars damage to the resort economy. This is similar in size to the oil spill from an onshore tank in Japan

last Christmas which polluted an area 80 miles long and 20 miles wide and which could not be contained because of high winds.

We have now read your Draft Environmental Impact Statement which admits that you have no reliable estimate of the damage that would result from this massive leasing program and which goes on to state on page 169, volume 2, "It is our conclusion, based on past performance that sooner or later a major spill will occur wherever there is significant development/offshore exploration and production in potential areas. We are certain that thousands of minor spills will occur." We note that your statement describes the industrialization of our County (page 228) with its attendant air and water pollution and huge influx of people.

✓ In numerous other public hearings, we adamantly opposed the construction of a deepwater port and induced oil-related development in this area. We opposed it in 1972. We opposed it in 1973. We opposed it in 1974. Your Environmental Impact Statement predicts and projects oil-related industrial development induced by accelerated Outer Continental Shelf leasing will be in addition to industrial development induced by the construction of a deepwater oil port in the environs of Cape May County.

Therefore, the Board of Chosen Freeholders of the County of Cape May and the Cape May County Planning Board go on record as strenuously opposing and protesting the proposed leasing of land in the vicinity of the New Jersey shore to oil companies for drilling purposes.

CAPE MAY COUNTY PLANNING BOARD

WHEREAS, activities on the Offshore Continental Shelf (OCS) have commenced and will, in all likelihood be expanded, and

WHEREAS a Draft Environmental Statement has been prepared by the Bureau of Land Management relating to the proposed 1976 OCS Oil and Gas Lease Sale Offshore the Mid-Atlantic States,

AND WHEREAS the Cape May County Planning Board has reviewed said EIS and has prepared a position paper regarding said proposed OCS activity;

THEREFORE, BE IT RESOLVED by the Cape May County Planning Board that said position paper, as attached hereto, is the official position of the Cape May County Planning Board and that said position be presented at hearings on this subject and be forwarded to appropriate local, state and federal officials, the press and general public for their endorsement and support.

William J. Diller, Jr. Chairman

Neil O. Clarke
Neil O. Clarke, Secretary

Adopted: January 20, 1976
Date

3035

DEPARTMENT OF INTERIOR
1976 OUTER CONTINENTAL SHELF
OIL AND GAS LEASE SALE NO. 40

January 27, 1976

STATEMENT OF THE
CAPE MAY COUNTY PLANNING BOARD
CAPE MAY COURT HOUSE, NEW JERSEY

I am Elwood Jarmer, Director of the Cape May County Planning Board and with me today is Robert Myers of our staff. We thank you in advance for the opportunity of appearing in response to your solicitation of public comment on the policy of proceeding with/sale number 40.

Generally the Draft Environmental Impact Statement on the proposed OCS Sale Number 40 is a great improvement over the draft so-called "generic" statement on the proposed accelerating leasing program in toto. However, our two prime areas of concern, oil spillage and induced on-shore industrial development, remain. Several specific statements in the draft merit comment, particularly those attempting to quantify the economy of Cape May County. On page 410 of Volume 1, appears Table II-79, "Tourism business receipts by type of Lodging". Under the column entitled Cape May County, New Jersey, the statistical data is patently incorrect. Receipts from the camping/trailer categories should be \$3,000,000, not \$1,242,000. commercial receipts \$61,000,000, not \$29,116,000, vacation homes \$54,000,000, not \$2,121,000 and the total tourism receipt should total in excess of \$120,000,000, not \$33,000,000. The importance of this error in your baseline data is profoundly reflected in conclusions reached elsewhere in the analysis and should be corrected. Likewise, Table II-83, "Total Tourism Generated Employment" should also be

ected. Tourism generated employment in August, 1974, was 740, not 4,490. That is incorrect by a factor of six. Table II-85 should also be corrected. Total County employment in August, 1974 46,200, not 10,412, at which time the seasonal work force 29,740, yielding a percentage of 223 percent seasonal work of the non-seasonal, not 43 percent as you indicate.

Table II-86 on page 420 of Volume 1 also misrepresents property taxes paid by the tourist sector. Local property taxes generated by tourist investment in 1973 exceeded \$19.9 million dollars, \$718,000. Incidentally the local property taxes paid to Cape May investment in 1973 attributable to direct and indirect/tourism facilities exceeded \$29,000,000.

\$242,000,000 were realized by tourist retail sales and rental businesses in Cape May County in 1973. This leads us to criticize the designation on page 544 Volume 1 of Cape May County as "The class of County having the most limited industrial base". While that statement is technically correct, the characterization is wrong and it is indicative of the Interior's Department lack of understanding that the New Jersey resort business is in fact an industry.

To be clear, tourism in New Jersey is the State's second largest industry. That misunderstanding is expressed again on page 555 of Volume 1. The statement, "The New Jersey shore resort areas experienced the significant increase in vacation activity in many years during the season". In fact, tourist retail sales have increased 548 percent since 1950.

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In Volume II, pages 194 and 195, the implication in the third paragraph is that the expansion of the industrial base of non-industrialized counties is desirable. Again the statement is technically true in the broad perspective but the fact is that Cape May County and other tourism oriented areas seek only certain specific types of non-smoke stack industries to complement their seasonal resort economies.

For example, electronic assemble facilities, colleges and marine research laboratories would, in our view, augment our seasonal resort economy. OCS staging areas, gas processing plants, and refineries would not.

The statement on page 197 of Volume II, "A county dependent on the tourist industry, for example, in expanding its industrial base would lessen its dependence on outside areas and vulnerability to the fluctuations and uncertainties associated with the tourist industry," is patently false. The industrialization of Puerto Rico is a poignant example to the contrary. Chronic pollution in San Juan Bay associated with population increases due to expansion of their industrial base signal the demise of a once prosperous resort industry. The simple truth is that tourism and heavy industry cannot peacefully coexist. The statement on page 197 continues, "Many of the problems associated with an unstable, unpredictable and limited economic base can be avoided by widening the industrial base and providing the economy with more certain earning power so as to meet the needs of the people within the County." In fact, the opposite is true. During the summer of 1974, while the nation and state were suffering the County tourist industry had one of

its best seasons ever. The same was true during the economic crunch of the 60's. As the 1975 season approached, and the Nation and State were still in a severe recession, real estate agents and motels reported a very high percentage of advance bookings. The 1975 season even exceeded that of 1974. During the same period, the Nation saw the closing of many / large manufacturing plant and cutbacks in/other manufacturing facilities. The lesson in this could be that the expansion of the economic base through manufacturing and heavy industrialization may increase the problems it is trying to solve. The resort industry of Cape May County and the coastal areas of New Jersey is simply not brought to its knees by cyclical periods of inflation and recession as are other industrially based economies. Even if Cape May County were to heavily industrialize as the result of OCS activity, what kind of an economy could we expect in 20 years when the mid-Atlantic OCS is depleted of hydro-carbon reserves? Our prosperous resort economy and the high quality natural environment which abounds in Cape May County is unlimited in time and gross dollar potential only if it is left unscathed by heavy industry. Just as the Nation needs energy, the Nation also needs recreational opportunities and Cape May County and the Jersey Shore have and should be allowed to fulfill that need. Once our fragile environment, upon which the resort economy so heavily depends, is destroyed can never be recreated by man.

On Page 165 of Volume II you state, "Refineries have not been

included as facilities, necessitated or stimulated by the proposed sale." Further, on page 11, also Volume II, you state that the average daily production will range between 43,000 and 285,000 barrel per day of production. In light of your statement on page 224 of Volume II of the draft "generic" EIS on the accelerated leasing program, "RPA and CEQ both conclude that 250,000 barrel per day offshore production would justify refinery development", a reasonable conclusion would be that at least one new refinery is a distinct possibility as a result of OCS

3040

Sale Number 40. With another Mid-Atlantic Sale proposed 18 months after the initial sale, the probability of new refinery development escalates.

Another issue raised in the Draft Environmental Impact Statement is the possibility of additional near-shore drilling. The Cape May County Planning Board questions the wisdom of moving drilling rigs and production equipment any closer to the shore line than is proposed in sale number 40. According to your analysis, the environmental risks escalate as drilling and production move closer to shore. The aesthetic impact on the resort economy of the New Jersey Shore would be devastating. Further, in your analysis you conclude that on-shore development necessary to support offshore facilities would proliferate as a result of such action. Further, as drilling approaches the shore line, the probability of chronic low level spillage and the possibility of a major spill from an off-shore rig, increase. Proliferation of on-shore industrial development and the increased

probability of sustaining a major oil spill are exactly the things the resort industry of the State of New Jersey and Cape May County are trying to avoid. Cape May County will resist such further proposals as vigorously as we intend to resist lease sale number 40.

Having documented the past and future economic vitality of Cape May County's resort economy and the potential negative impacts of oil spillage and industrialization would have on that economy and the natural environment of the region, the Cape May County Planning Board must oppose OCS Lease Sale Number 40. Failing Federal action to preserve the resort economy and fragile natural environment, we will continue to oppose OCS development and the accelerated leasing program.

While we endorse the efforts of the Interior Department to ameliorate the potential negative impacts of OCS activity through the OCS operating orders, those orders and special stipulations are inadequate protective devices for the concern we have for Cape May County. If opposition to Sale #40 is unsuccessful we will insist that stipulations and OCS operation orders as they effect Cape May County be substantially modified and enlarged. As a minimum, the proposed lease stipulation regarding designated pipeline corridors (page 356, II) should be written to provide for consistency of the Bureau of Land Management Plan and the affected State Coastal Zone Management Plan and any adopted regional plan designating pipeline corridors. Onshore support and processing facilities should also comply.

Lease stipulations should also provide for regional participation in the two-phase pipeline corridor study also cited on page 356 - Volume II.

The importance of coordinating this study at all affected levels is made clear on page 228. "The general location of many of the facilities which would be required on shore as a result of the proposed sale would be a function of where pipelines are allowed to come ashore." This is particularly important in the context of water availability. Recent studies by the State of New Jersey and the Cape May County Planning Board indicate that water availability in Cape May County will be limited in the future. With gas processing facilities consuming 15,000 gallons of water per day or 5,475,000 gallons per year, that impact on tourism is significant. One gas processing plant in Cape May County, at that rate of usage would consume as much water as 56,000 summer visitors.

As refineries consume 40 gallons of water for each barrel of crude oil processed, the impact of a refinery would be devastating in terms of water withdrawal alone.

In addition to these stipulations regarding pipeline corridors, we submit that as a matter of policy, pipeline corridors should not be permitted to traverse any ocean dumping sites so as to avoid the resuspension of heavy metals and other pollutants in the water column. (page 362-Volume II). The stipulation regarding transport of crude oil from platforms via tankers should also be amended. We recommend amendment to prohibit lightering to barges even though that possibility is characterized as small.

Another stipulation must be written into the leases requiring the use of the best available technology to reduce and ameliorate the aesthetic impact of the introduction of noxious air borne sulphur dioxide from gas processing plants and other onshore facilities. On page 242 of Volume II, you indicate the "technology exists to restrict the quantity of these emissions." This proposed regulation must also specify a minimum distance of all induced onshore facilities from existing tourist and recreation areas. That distance must be established in conjunction with and acceptable to local and county government.

Due to the fragile eco-system of the wetlands and their high environmental productivity, the OCS operating orders should require that the oil spill contingency plans provide a system of booms or other technology to close inlets between the coastal barrier islands in the event of an oil spill when such a spill threatens those wetlands.

The report also projects oil spills and attempts to quantify their impacts. No one wants to be responsible for the spilled oil. We have demonstrated the relationship between the resort economies of the coastal communities of the State of New Jersey and the high quality natural environment. Those coastal communities are a unique physical and natural resource that should be protected. We have cited the existing vitality of the resort economy and its potential long-term vitality. The need to protect our natural environment and our economic base, the resort economy, is clear. Equally clear is the necessity for Federal responsibility in the event of oil spills. We heartily endorse the concept of a super fund to indemnify our County in the event of a spill.

The Environmental Impact Statement projects as a result of OCS Sale Number 40, the industrialization and resultant urbanization of Cape May County. It describes the destruction of existing land use patterns and natural environments, degradation of air and water quality and economic and social dislocation as onshore impacts. References abound to induced onshore development and industrialization.

Essentially, the negative impacts of OCS Sale Number 40 are crystalize in two issues: oil spillage and induced onshore industrial development. Through this Environmental Impact Statement, the Federal Government has told the residents of the Mid-Atlantic region they won't be responsible for oil spill damage and can't be responsible for onshore development.

In our comments on the draft generic Environmental Impact Statement on the Accelerated OCS Leasing Program, we said that the Federal Government should not sell OCS Lease sale areas and ignore the consequences. We stand by that statement. We will continue to resist to the fullest extent possible the attempt to industrialize, urbanize and destroy the environment and resort economy through federally authorized OCS activities. The Cape May County Planning Board therefore urges you to withhold OCS Sale Number 40.



Interior Department's Estimate of the Cost
of Finding Hydrocarbons for the OCS Sale #40 Acreage
for the Low Reserves Estimate Case

3046

I. Estimated Reserves

(a) Oil	0.4 Billion Barrels	=	2,240,000,000 MMBtu
(b) Natural Gas	2,6 Trillion Cubic Feet	=	2,860,000,000 MMBtu
Total			5,100,000,000 MMBtu

II. Estimated Finding Costs

(a) Exploratory Wells	\$ 180,000,000
(b) Development Wells	240,000,000
(c) Platforms and Equipment	200,000,000
(d) Service Support Equipment	5,200,000
Total	\$ 625,200,000

III. Estimated Findings Costs
in Cents per Million Btu

12.26¢

Source: "Program Decision Option Document Sale #40 Mid-Atlantic OCS";
U.S. Interior Department (1976).

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3047

Interior Department's Estimate of the Cost of Finding
Hydrocarbons for the OCS Sale #40 Acreage
for the High Reserves Estimate Case

I. Estimated Reserves

(a)	Oil	1.4 Billion Barrels	=	\$ 7,840,000,000	MMBtu
(b)	Natural Gas	9.4 Trillion Cubic Feet	=	10,340,000,000	MMBtu
Total				\$ 18,180,000,000	MMBtu

II. Estimates Finding Costs

(a)	Exploratory Wells	720,000,000
(b)	Development Wells	910,000,000
(c)	Platforms and Equipment	1,000,000,000
(d)	Service Support Equipment	5,200,000
Total		\$ 2,635,200,000

III. Estimated Finding Costs
in Cents per Million Btu

14.50¢

Source: "Program Decision Option Document Sale #40 Mid-Atlantic OCS";
U.S. Interior Department (1976).

3048

Estimated Cost of Finding
New Crude Oil in the Lower 48 States,
in cents per Barrel and in cents per Million Btu
(1974)

<u>Cost Components</u>	(1) 1973 in ¢/Barrel	(2) 1974 in ¢/Barrel	(3) 1974 in ¢/MMBtu
Successful well costs	53.0	66.0	11.78
Dry Hole Costs	26.0	36.0	6.43
Other Production Facilities	33.0	43.0	7.68
Other Exploration Costs	24.0	30.0	5.36
Exploration Overhead	7.0	9.0	1.61
Total Finding Costs	143.0	184.0	32.86

- Sources: Column (1) - "Staff Analysis Of The Cost Of Finding And Producing New Crude Oil," Bureau of Natural Gas, Federal Power Commission, June 1975.
- Column (2) - Column (1), adjusted to reflect 1974 drilling and expenditure data.
- Column (3) - Column (2) ÷ 5.6; this assumes that each barrel of new crude oil contains 5,600,000 Btu of energy.

Estimated 1976 Finding Costs for
New, Non-Associated Natural Gas in the United States,
in cents per Mcf and in Cents per Million Btu

<u>Cost Component</u>	(1) <u>¢/Mcf</u>	(2) <u>¢/MMBtu</u>
Successful Well Costs	9.79	8.90
Dry Hole Costs	4.16	3.78
Other Production Facilities	2.27	2.06
Other Explanatory Costs	8.45	7.68
Exploration Overhead	3.56	3.24
Total Finding Costs	28.23	25.66

Sources: Column (1) - "National Rates for Natural Gas, Docket No. Rm 75-14", Office of Economics, Federal Power Commission (September 29, 1975).
Column (2) - Column (1) ÷ 1.1; this assumes that each Mcf of natural gas contains 1,100,000 Btu of energy.

3050

Estimated Cost of Finding
New, Non-Associated Natural Gas in the United States,
in cents per Mcf and in Cents per Million Btu
(1975)

<u>Cost Components</u>	(1) <u>¢/Mcf</u>	(2) <u>c/MMbtu</u>
Successful Well Costs	12.84	11.67
Dry Hole Costs	8.12	7.38
Other Production Facilities	3.44	3.13
Other Exploratory Costs	4.73	4.3
Exploration Overhead	1.71	1.55
Recompletion Costs	0.50	0.45
Total Finding Costs	31.34	28.48

Sources: Column (1) - Federal Power Commission, Opinion No.770
July 27, 1976.

Column (2) - Column (1) ÷ 1.1; this assumes that each
Mcf of natural gas contains 1,100,000 Btu
of energy.

Estimated Offshore Large Diameter Pipeline Costs
High Island Offshore System,
Gulf of Mexico

<u>System Segment</u>	<u>Pipeline Diameter</u>	<u>Miles</u>	<u>Cost</u>	<u>Per</u>
Block 264 to Block 167	42 inch	67	\$ 93,738,400	\$1,39
Block 343 to Block 264	36 inch	26	34,408,810	1,32
Block 330 to Block 343	30 inch	15	17,011,160	1,13
Block 573 to Block 264	30 inch	41	41,909,120	1,02
Block 582 to Block 264	30 inch	54.5	54,220,180	99
Block 264 Compressor Complex	-	-	70,349,600	
Offshore Manifold Platforms	-	-	41,089,090	
		203.5	\$ 352,726,360	\$1,733

Source: High Island Offshore System, FPC Docket No. CP 75-104, et al., Amendment To Application For Certificates of Public Convenience and Necessity, September 8, 1975.

Estimated Realistic Investment Costs, Mid-Atlantic
Sale #40, for Low Case Reserves Estimate
of 5,100,000,000 Million Btu

Cost
r Mile

9,080

3,416

4,077

2,174

4,866

-

-

0,299

ations

Cost Component	If Cost of Finding and Producing Hydrocarbons Is	
	(1)	(2)
	25.66¢/MMBtu	32.86¢/MMBtu
(1) Finding Costs	\$1,308,660,000	\$1,675,860,000
(2) Large Diameter Pipeline @ \$1,733,300 per mile	173,330,000	173,330,000
(3) Pipeline Terminal Storage Facilities	4,000,000	4,000,000
(4) Onshore Operations Facilities	2,800,000	2,800,000
(5) Gas Processing Plants	120,000,000	120,000,000
(6) Total Estimated Realistic Investment Costs	\$1,608,790,000	\$1,975,990,000
(7) Interior Department's Estimates	\$ 852,000,000	\$ 852,000,000
(8) Amount by Which Interior Department Underestimated Investment Costs for Sale #40	\$ 756,790,000	\$1,123,990,000
(9) Percent by Which Realistic Investment Costs Exceed Interior Department's Estimate	88.8%	131.9%

3053

Estimated Realistic Investment Costs, Mid-Atlantic Sale #40,
for High Case Reserves Estimate of 18,180,000,000 Million Btu

<u>Cost Component</u>	<u>If Cost of Finding and Producing Hydrocarbons is:</u>	
	<u>(1)</u> <u>25.66¢/MMBtu</u>	<u>(2)</u> <u>32.86¢/MMBtu</u>
(1) Finding Costs	\$4,664,988,000	\$5,973,948,000
(2) Large Diameter Pipeline @ \$1,733,300 per Mile	779,985,000	779,985,000
(3) Pipeline Terminal Storage Facilities	8,000,000	8,000,000
(4) Onshore Operations Facilities	5,600,000	5,600,000
(5) Gas Processing Plants	<u>240,000,000</u>	<u>240,000,000</u>
(6) Total Estimated Realistic Investment Costs	\$5,698,573,000	\$7,007,533,000
(7) Interior Department's Estimate	\$3,338,800,000	\$3,338,800,000
(8) Amount by Which Interior Department Underestimated Investment Costs for Sale #40	\$2,359,773,000	\$3,668,733,000
(9) Percent by Which Realistic Investment Costs Exceed Interior Department's Estimate	70.7%	109.9%

3054

Annual Natural Gas Production As A Percent of Proved Reserves
for Future Offshore Gas Reserves Additions

<u>Full Year of Production</u>	<u>Production As A Percent of Reserves</u>
1	10.0
2	9.0
3	8.0
4	7.0
5	7.0
6	7.0
7	6.7
8	5.8
9	5.0
10	4.4
11	3.8
12	3.5
13	3.0
14	2.6
15	2.4
	85.2

Source: Production rates applicable to offshore reserves additions, as developed by Exxon, USA for the Federal Power Commission's Natural Gas Survey.

3055

Annual Crude Oil Production As A Percent Of Reserves
Added And Associated Gas Production
Per Barrel Of Crude Oil Production For
Crude Oil Reserves Discovered In 1974

Year of Production	Total Oil Production		Associated Gas Production	
	(1) (1000 bls)	(2) (% of Reserves)	(1) (1000 Mcf)	(2) (Mcf/Bbl.)
1974	40,962	3.43	57,429	1.4
1975	81,924	6.86	114,857	1.4
1976	81,924	6.86	114,858	1.4
1977	81,924	6.86	114,857	1.4
1978	81,924	6.86	114,858	1.4
1979	81,924	6.86	114,857	1.4
1980	81,924	6.86	114,857	1.4
1981	80,720	6.75	113,169	1.4
1982	72,706	6.08	101,935	1.4
1983	64,487	5.40	90,410	1.4
1984	57,197	4.79	80,190	1.4
1985	50,731	4.24	71,125	1.4
1986	44,995	3.76	63,084	1.4
1987	39,910	3.34	55,953	1.4
1988	35,397	2.96	49,627	1.4
1989	31,396	2.63	44,017	1.4
1990	27,847	2.33	39,041	1.4
1991	24,698	2.07	34,628	1.4
1992	21,907	1.83	30,712	1.4
1993	19,430	1.62	27,241	1.4
Sub-total	1,103,927	92.38	1,547,705	1.4
Remaining	91,073	7.62	127,685	1.4
Total Reserves Added	1,195,000	100.00	1,675,390	1.4

Source: "Calculation of New Oil Costs, United States, Years 1959 Through 1974";
La Rue, Moore & Schafer, Petroleum Consultants, Dallas, Texas (May 1, 1975).

3056

**Oil and Associated Gas Reserves Required If OCS Sale #40
Acreage Is To Produce At Levels Contained In The
Interior Department's Program Decision Option Document
Low Reserves Case**

<u>Oil Production</u>		<u>New Reserves Brought Onstream That Year</u>		<u>Cumulative Reserves Brought Onstream</u>	
<u>(1000 Bbls.)</u>	<u>(Bbls./Day)</u>	<u>(1000 Bbls.)</u>	<u>(1000 Mcf)</u>	<u>(1000 Bbls.)</u>	<u>(1000 Mcf)</u>
1,825	5,000	26,603	37,244	26,603	37,244
4,562	12,499	39,898	55,857	66,501	93,101
7,300	20,000	39,912	55,877	106,413	148,978
11,862	32,499	66,501	93,101	172,914	242,079
16,425	45,000	66,516	93,122	239,430	335,201
20,531	56,249	59,854	83,796	299,284	418,997
24,637	67,499	60,277	84,388	359,561	503,385
28,743	78,748	63,105	88,347	422,666	591,732 .
32,850	90,000	67,041	93,857	489,707	685,589

Associated And Non-Associated Gas Reserves Required If OCS Sale #40 .
Acreage Is To Produce At Levels Contained In The Interior Department's
Program Decision Option Document, Low Reserves Case

	Total Gas Production		Associated Gas Production (1000 Mcf)	Non Associated Gas Production (1000 Mcf)	New Reserves Brought Onstream That Year		Cumulative Reserves Brought Onstream		
	(1000 Mcf)	(Mcf/Day)			Associated (1000 Mcf)	Non-Associated (1000 Mcf)	Associated (1000 Mcf)	Non-Associated (1000 Mcf)	To (1000 Mcf)
1981	5,475	15,000	2,555	2,920	37,244	29,200	37,244	29,200	66,4
1982	17,338	47,501	6,387	10,951	55,857	83,230	93,101	112,430	205,5
1983	29,200	80,000	10,220	18,980	55,877	91,530	148,978	203,960	352,9
1984	69,350	190,000	16,607	52,743	93,101	358,030	242,079	561,990	804,0
1985	109,500	300,000	22,995	86,505	93,122	390,900	335,201	952,890	1,288,0
1986	159,688	437,501	28,743	130,945	83,796	528,450	418,997	1,481,340	1,900,3
1987	209,875	575,000	34,492	175,383	84,388	572,990	503,385	2,054,330	2,557,7
1988	260,062	712,501	40,240	219,823	88,347	598,760	591,732	2,653,090	3,244,8
1989	310,250	850,000	45,990	264,260	93,857	626,960	685,589	3,280,050	3,965,6

3058

Oil and Associated Gas Reserves Required If OCS Sale #40 Acreage Is To Produce
At Levels Contained In The Interior Department's Program Decision Option Document,
High Reserves Case

	Oil Production		New Reserves Brought Onstream That Year		Cumulative New Reserves Brought Onstream	
	(1000 Bbls.)	(Bbls./Day)	(1000 Bbls.)	(1000 Mcf)	(1000 Bbls.)	(1000 Mcf)
1981	9,125	25,000	133,017	186,224	133,017	186,224
1982	20,075	55,000	159,621	223,469	292,638	409,693
1983	31,025	85,000	159,621	223,469	452,259	633,162
1984	47,450	130,000	239,431	335,203	691,690	968,365
1985	63,875	175,000	239,431	335,203	931,121	1,303,568
1986	77,106	211,249	192,872	270,021	1,123,993	1,573,589
1987	90,337	247,499	195,000	273,000	1,318,993	1,846,589
1988	103,568	283,748	208,440	291,816	1,527,433	2,138,405
1989	116,800	320,000	224,213	313,898	1,751,646	2,452,303
1990	113,572	311,156	-0-	-0-	1,751,646	2,452,303
1991	108,913	298,392	-0-	-0-	1,751,646	2,452,303
1992	102,977	282,129	-0-	-0-	1,751,646	2,452,303

3053

Associated And Non-Associated Gas Reserves Required If OCS Sale #40 Acreage Is
To Produce At Levels Contained In The Interior Department's Program Decision Option Document,
High Reserve Case

	Total Gas Production		Associated Gas Production (1000 Mcf)	Non-Associated Gas Production (1000 Mcf)	New Reserves Brought Onstream That Year		Cumulative Reserves Brought Onstream		
	(1000 Mcf)	(Mcf/Day)			Associated (1000 Mcf)	Non-Associated (1000 Mcf)	Associated (1000 Mcf)	Non-Associated (1000 Mcf)	Total (1000 Mcf)
1981	14,600	40,000	12,775	1,825	186,224	18,250	186,224	18,250	204,474
1982	51,100	140,000	28,105	22,995	223,469	213,530	409,693	231,780	641,473
1983	87,600	240,000	43,435	44,165	223,469	234,870	633,162	466,650	1,099,812
1984	226,300	620,000	66,430	159,870	335,203	1,203,720	968,365	1,669,370	2,637,735
1985	365,000	1,000,000	89,425	275,575	335,203	1,322,250	1,303,568	2,991,620	4,295,188
1986	554,800	1,520,000	107,948	446,852	270,021	1,988,850	1,573,589	4,980,470	6,554,059
1987	774,600	2,122,192	126,472	618,128	273,000	2,164,800	1,846,589	7,145,270	8,991,859
1988	934,400	2,560,000	144,995	789,405	291,816	2,268,410	2,138,405	9,413,680	11,552,085
1989	1,124,200	3,080,000	163,520	960,680	313,898	2,382,680	2,452,303	11,796,360	14,248,663
1990	1,043,980	2,860,219	159,001	884,979	-0-	-0-	2,452,303	11,796,360	14,248,663
1991	972,877	2,665,416	152,478	820,399	-0-	-0-	2,452,303	11,796,360	14,248,663
1992	910,498	2,494,515	144,168	766,330	-0-	-0-	2,452,303	11,796,360	14,248,663

3060

3053

Document,

<u>Brought Onstream</u>	<u>Total</u>
<u>ciated</u>	<u>(1000 Mcf)</u>
<u>Mcf)</u>	

50	204,474
80	641,473
50	1,099,812
70	2,637,735
20	4,295,188
70	6,554,059
70	8,991,859
80	11,552,085
60	14,248,663
60	14,248,663
60	14,248,663
60	14,248,663

3061

DEEP ONSHORE DRILLING PROSPECTS FOR THE LOWER 48 STATES

ROBERT A. HEFNER III

AGA Transmission Conference
May, 1975

Deep Onshore Drilling Prospects for the Lower 48 States

(75-T-23)

3062

ROBERT A. HEFNER III,
The GHK Co./Gassandarko, Ltd.

I will concentrate today on new natural gas — gas that can be started toward the market in significant amounts beginning in the next two to three years. The majority of that gas will be delivered from areas which are the subject of my remarks — the deep onshore lower 48. I believe the majority of that gas will come from the vast volume of sediments below 15,000 feet. These sediments are presently unexplored and are in traditional supply areas with existing transportation systems.

When we speak of "recoverable reserves" we must consider the economics and also ask — will these reserves be produced during the time the consumer requires them? Timing of the delivery of these reserves can be as important as the economics.

It is my opinion that supply and demand for natural gas can be brought into balance between now and the early 1980's largely by the development of deep onshore lower 48 gas; but only if Congress immediately deregulates new natural gas, an action it deemed wise twice before (after lengthy and exhaustive deliberation), an action with positive environmental impact and minimal (if any) inflationary impact.

I should like to point out our experience in Oklahoma. Oklahoma is a natural gas producing (1.77 TCF in 1974), consuming (estimated 670 BCF in 1974), and exporting (estimated 1.1 TCF in 1974) state, in fact consuming about the same amount of natural gas in 1974 as the state of New York. Only 13% of the natural gas consumed in Oklahoma is supplied by interstate pipelines; therefore, within Oklahoma (a major consuming state) we have a working free market system. We believe the "Oklahoma Experience" over the past five years is particularly informative and a vital and necessary consideration by those charged with the responsibility of formulating energy policy for natural gas.

Oklahoma, through its free market system in natural gas, has provided for the consumers of our state a firm and growing supply which has met Oklahoma's 4.5% per annum increase in demand at an increase in cost to the residential consumer of only 4.8% per annum! The free market system in Oklahoma has been tried and proven to accomplish all the stated goals of those who are deliberating national energy policy:

1. Added domestic supplies.
2. Non-inflationary additional cost to the consumer.
3. Reduced rates of growth in demand.
4. Eliminated additional and unnecessary reliance on foreign supplies.

Oklahoma is further unique in that the free market system in our State has arrested the decline in proven reserves for consumption in Oklahoma and has increased those reserves by 1% thereby maintaining a stable production to reserve ratio over the last five years. In short, Oklahoma has achieved balance in supply and demand and without OPEC Cartel prices.

The "Oklahoma Experience" 1970 through 1974

New Natural Gas Prices: Intrastate wellhead sales prices increased from 21.5¢/Mcf to 35¢/Mcf = 41% per annum.

Average Wellhead Prices: Average intrastate wellhead sales prices increased from 18.74¢/Mcf to 44.13¢/Mcf = 23.9% per annum.

Natural Gas Demand: Demand increased 4.5% per annum.

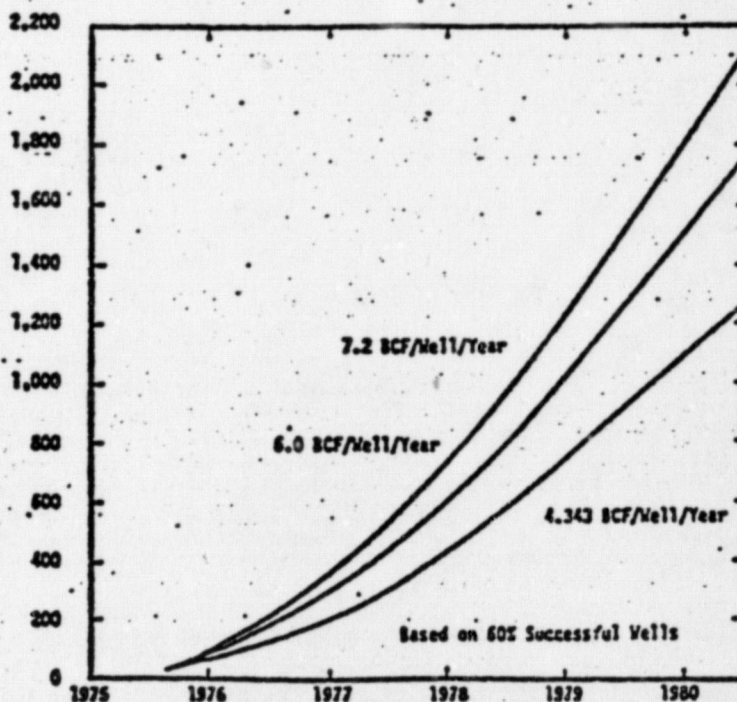
Average Residential Natural Gas Costs: Average residential natural gas cost increased from 87¢/Mcf to \$1.05/Mcf = increase of 4.8% per annum.

Net Reserves: Increased 1%, reserve production ratio remained stable.

Given our proof from the Oklahoma real-life experience that in natural gas the free market system does in fact work to the benefit of consumers and industry and to the benefit of government, national security and economic well-being; then we consider it unconscionable to propose the regulatory system in the name of "consumerism" unless it can be shown in real life examples to be superior to the system upon which this country was founded and has grown in most all fields of human endeavor to levels unsurpassed in world history.

Another area which is extremely important to the natural gas industry is the amortization of \$15 billion invested in existing pipeline transportation systems. Many of the members of the American Gas Association are associated with various gas transmission and distribution companies. If yours is the typical interstate natural gas transmission or distribution company, you are depreciating your fixed plant and equipment on a 30- to 33-year-life basis. It ranges from as low as 25 years for some of you

ANNUAL PRODUCTION FROM A CONCENTRATED DEVELOPMENT EFFORT
IN THE DEEP ANADARKO BASIN (BCF/YEAR)



DEVELOPMENT OF THE DEEP ANADARKO BASIN
(1974)

BEST COPY AVAILABLE

of at least one oil spill over 1,000 barrels is about 27 percent during the life of a small field, about 85 percent for a medium field, and nearly 100 percent for a large field. The expected time interval between spills larger than 1,000 barrels is approximately 2.5 years for a small field, slightly over one year for a medium field, and slightly over one half a year for a large field.

Pipeline Spills

Pipeline accidents have released more oil to the marine environment than all other sources directly related to OCS operations. The largest spills occurred prior to 1970 and resulted from pipeline ruptures caused by anchor dragging. One of the largest pipeline spills occurred in October 1967 when a vessel dragging its anchor in a storm severed a pipeline about 30 miles west of the mouth of Southwest Pass, Mississippi River delta, Louisiana. The resulting spill went undetected for ten days and released over 160,000 bbl of oil into the Gulf of Mexico. Four major pipeline breaks have occurred on the OCS. Since 1970 spillage from pipelines has been considerably reduced as a result of several actions.

Beginning in 1969, the Bureau of Land Management has required all new common carrier pipelines to be buried a minimum of three feet out to a water depth of 200 feet. In shipping lanes and anchor-ages areas, pipelines must be buried at least 10 feet deep. Only lines in the gathering system between adjacent platforms may remain unburied. In some areas, such as the Southern California OCS, the water depth requirement may be increased to 250 feet. In addition, offshore pipelines are required to be coated with moisture impervious materials followed in many cases by a layer of dense concrete for mechanical protection. Electrolytic protection against corrosion is also required. Other regulations call for continuous line pressure monitoring systems with automatic shut down valves or alarms, and regular pipeline inspection for leaks.

Industry spokesmen estimate that 48 percent of all pipeline leaks occur in lines that have been in use for 15 years or more. This would suggest that the recent improvement in pipeline spillage may not continue as existing pipelines, especially those installed before 1970 which may not be coated or buried, reach states of more advanced corrosion. The MIT spill analysis projects about a 25 percent probability of one pipeline spill over 1,000 barrels over the life of a small field, about a 70 percent chance of one such spill for a medium field, and a 95 percent probability for a large field.

Oil Spills From Natural Hazards—Hurricanes

In the history of OCS oil and gas activities, only one natural hazard has caused significant oil spillage. On October 3, 1964, three platforms off central Louisiana were destroyed by a hurricane. The total volume of oil spilled was approximately 12,000 barrels, all of which was from tanks on the platforms. Several major hurricanes have passed through the petroleum production areas in Federal waters of the Gulf of Mexico and have caused financial damage to the OCS. Another problem is that water as it flows past the barrier is exceeded, oil will rise above the water level. When the same way as an iceberg rises above the water level, the barrier is exceeded, oil will rise above the water level. When the same way as an iceberg rises above the water level, the barrier is exceeded, oil will rise above the water level.

CONTAINMENT BARRIERS

Oil spill containment barriers are designed to be towed, ranging from protected waters beyond the barrier. Several types of barriers have been used in the past, including short curtains, floating booms, and large, anchored barriers. Typical barriers have a thickness of the slick. In a current, one problem is that the barrier is exceeded, oil will rise above the water level. When the same way as an iceberg rises above the water level, the barrier is exceeded, oil will rise above the water level. When the same way as an iceberg rises above the water level, the barrier is exceeded, oil will rise above the water level.

tests, and sea bird populations would have been greater (likely resulting in more mortalities).

Other factors influencing the severity of the impact from a spill are the oceanographic and meteorological conditions in the spill area. Wind and currents may drive floating oil either onshore or offshore. Currents and wave action combine to spread and dilute the spilled oil, thus reducing its toxicity. On the other hand, wave action may intensify problems especially near shore, as apparently occurred at West Falmouth. At West Falmouth, onshore winds churned oil with sediments and drove the oil ashore into the surrounding marshland. The oiled sediments and marshland then became a reservoir of oil for many months.

At Santa Barbara, the spill occurred during a period of heavy storms that brought flood waters bearing great amounts of sediments into the coastal waters. The sediment-laden fresh water provided an adsorptive surface for the spilled oil causing much of it to settle on the bottom rather than on the shore. Sedimentation is advantageous if the intertidal life is abundant, but it may be detrimental to benthic (bottom-dwelling) life.

An improper method of cleaning up an oil spill can increase the impact of oil pollution rather than diminish it. Mechanical methods are considered the least damaging to the environment. These methods include the use of booms and skimmers or the spreading and retrieval of absorbent material. Sinking agents acting in the same way as naturally turbid water, transfer the effects from intertidal coastal areas to offshore bottom-dwelling fauna, and may extend the duration of the impact. The use of dispersants is controversial and has been shown to be helpful in some cases and harmful in others, depending on the toxicity of the dispersant and the particular organisms one is intending to protect. Low-toxicity dispersants have the advantage of preventing oil from washing ashore and killing intertidal organisms, but pose an additional burden on the assimilative capacity of the marine environment. Cleanup technology will be discussed more fully in another section.

IMPACTS OF DRILLING

One of the most hazardous steps in offshore oil and gas development is exploratory drilling. The hazard potential is greatest when drilling into an unknown formation because of the possibility of encountering an unexpected sudden surge of pressure up the drill hole causing a blowout or loss of well control. Most blowouts involve only gas which is less environmentally damaging than if oil is released. An analysis of major OCS accidents by the University of Oklahoma Technology Assessment Group found that out of a total of 19 blowouts that occurred during drilling through the years 1953-1972, 17 involved gas only and 2 involved both oil and gas. The Santa Barbara blowout was one of

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MARCH 1976



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Hon. John M. Murphy, Chairman
PREPARED PURSUANT TO THE REQUEST OF
A STUDY
EFFECTS OF OFFSHORE OIL AND
NATURAL GAS DEVELOPMENT ON
THE COASTAL ZONE

94th Congress
2d Session
COMMITTEE PRINT

Pages 3074
to 3077 are
not included
in this appendix

Stratigraphy. Fig. 2 shows the Jurassic section penetrated in southern Alabama and the Florida Panhandle. The Louann salt of probable Middle Jurassic age is overlain by the Norphlet, a sand section predominantly of phlet, a sand section predominantly of the Smackover, a carbonate which is overlain by the evaporites of the Buckner. Above the Buckner is the upper Haynesville formation which consists of red, fine-to-coarse-grained clastics interbedded with evaporites. This whole sequence is capped by the Cotton Valley group.

The Appalachian structural trend (Fig. 3) and other pre-Jurassic tectonic elements, such as the Conocochee and Pensacola ridges, had significant influence on the distribution of Jurassic sediments, serving as the source area for basal Jurassic clastics and those clastics deposited during the Smackover transgression.

Smackover sediments adjacent to the Appalachian trend are composed of a mixture of clastics and carbonates. Most production in the Jurassic trend is basinward from this mixed lithology, occurring mostly in areas containing grainstone facies. The shallow-water carbonates of the Smackover were deposited on a broad shelf in the area of the Florida Panhandle, a shelf which narrowed considerably toward Mississippi. Wide-spread distribution of shallow-water carbonates on this shelf provided ideal conditions for the development of stratigraphic traps.

In Mississippi, the producing Smackover reservoir is generally an oolitic facies. In southern Alabama and in the Panhandle, the grainstone facies is composed of hardened pellets with oolites contributing a very minor part of the section. Development of this lower energy facies in the Jay area can be attributed to the dissipation of wave energy over a wide shelf and to the absence of topographic features which create a focal point for generation of oolites.

Porosity. An example of the porosity distribution and its relation to the lithology of the Smackover formation in Jay field can be seen in Fig. 4. This is a density log of Exxon-LAB-1 Jones McDavid, the field-confirmatory success. It shows the Smackover to have a thickness of about 370 ft. The bottom contact of the Smackover with the fine-grained Norphlet sandstone is typically sharp, whereas the

transition at the top into the Buckner evaporites is gradual. Structure and trap. Production at Jay occurs on the south plunge of a large subsurface anticline with the up-dip trap formed by a facies change. The Flomaton anticline, which produces Norphlet gas, continues to rise another 350 ft to its crest. Other structurally important features include the steep northeast flank, the Gilbertown-Pickens-Pollard fault to the east, and the small closures along the crest of the nose which trap oil in the underlying Norphlet, but reserves are only about 1% of those of the Smackover. Jay's productive area covers about 14,000 acres.

Fig. 2 shows the Jurassic section penetrated in southern Alabama and the Florida Panhandle. The Louann salt of probable Middle Jurassic age is overlain by the Norphlet, a sand section predominantly of phlet, a sand section predominantly of the Smackover, a carbonate which is overlain by the evaporites of the Buckner. Above the Buckner is the upper Haynesville formation which consists of red, fine-to-coarse-grained clastics interbedded with evaporites. This whole sequence is capped by the Cotton Valley group.

Sedimentary sequence

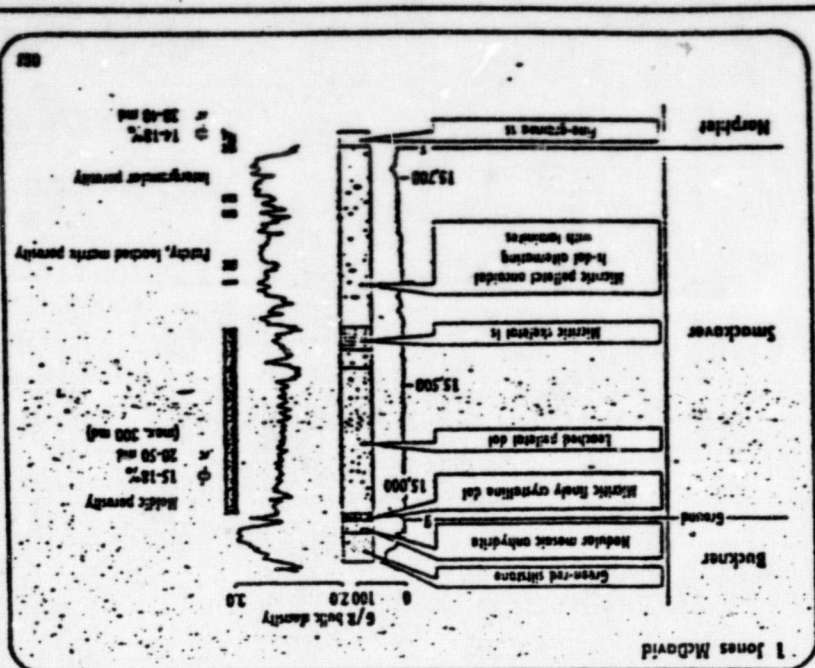


Fig. 4

Regional setting

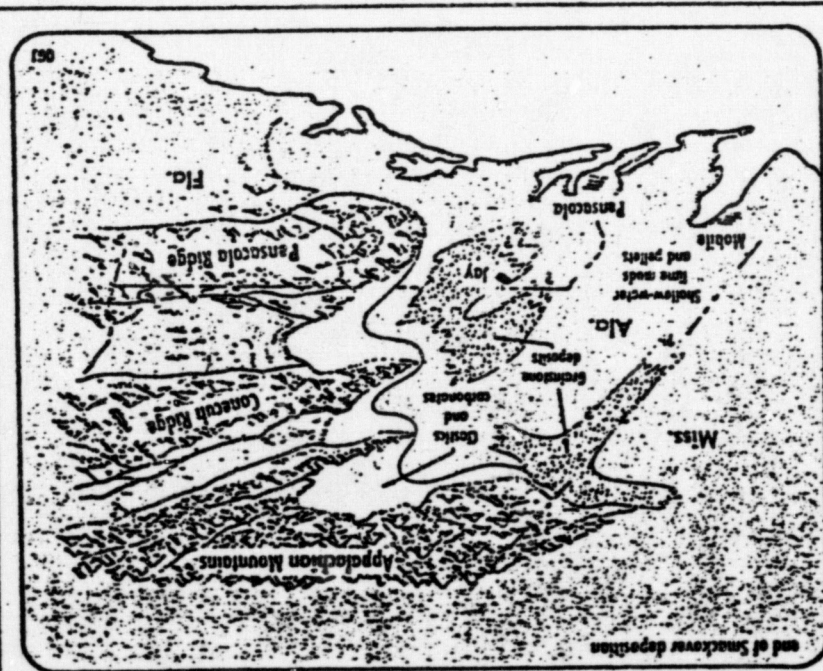


Fig. 3

Jay field—a classic Jurassic strat trap

followed in 1970 when dolomitized Smackover was found on a structural nose about 7 miles south of Flomaton. Other strikes then were Womack Hill, Chatom, Big Escambia Creek, and Blackjack Creek.

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Exxon Co. U.S.A.
Midland, Tex.

P. L. KEYES
Exxon Co. U.S.A.
Houston

M. A. ZIEGLER
Esso Production Research Co.
Houston

JAY field is the most important discovery in the United States since Prudhoe Bay was opened in 1968. Current estimates indicate that recoverable reserves exceed 300 million st-tank bbl of oil and 300 billion cu ft of gas. In a year's time after Jay was opened, 35 miles of north Pensa-

cola, Fla., Santa Rose County, over 100 wildcats were drilled in adjoining Alabama and Florida counties. Most Jurassic traps are very subtle and the key to exploring here lies in the ability to combine favorable facies with delineation of low relief structures. Without question, many more significant oil and gas accumulations are yet to be found in this area. The Jay discovery (Fig. 1) points up that there are still large reserves in the U.S. yet to be discovered.

This is a condensed version of a paper given at the Gulf Coast Association of Geological Societies in Houston, 1973. The entire paper appears in the Transactions of that meeting.

Exploration for Jurassic Smackover in Alabama and Florida was a logical extension along trend of the discoveries of the first three periods. In 1958, the fourth period began with a Norphlet discovery on a well-defined structure at Flomaton, 90 miles east of nearest Jurassic production. Jay

18,000 ft. at depths ranging from 12,000 ft to 25,000 ft, and the new-found ability to dig this deep. During this time, exploration shifted to southern Mississippi where 38 new fields were found at depths ranging from 12,000 ft to 18,000 ft.

Interest in Smackover Jurassic exploration was rejuvenated in the years 1960-68 as a result of the development of CDP seismic techniques which extended structural definition to as deep as 25,000 ft, and the new-found ability to dig this deep. During this time, exploration shifted to southern Mississippi where 38 new fields were found at depths ranging from 12,000 ft to 18,000 ft.

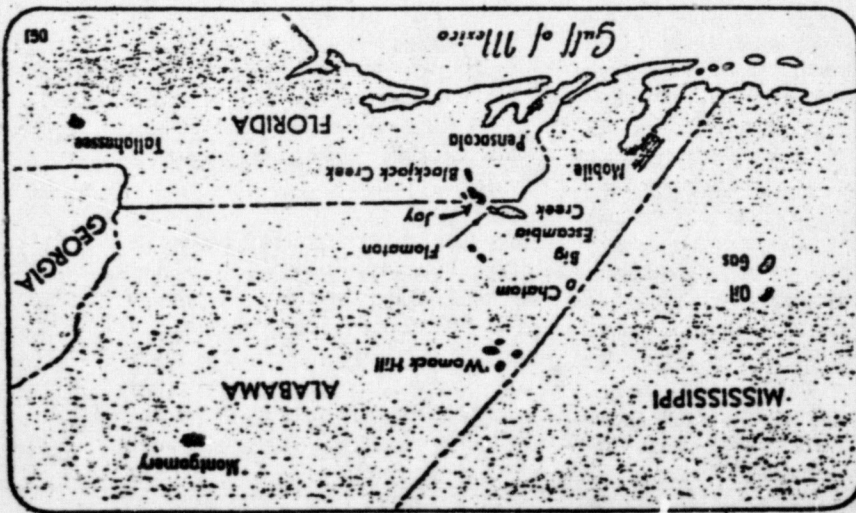


Fig. 1

Stratigraphic nomenclature

Series	Stages	Discovery well	Groups and fans
Lower	Bartonian	1 St. Regis	Cotton Valley
Upper Jurassic	Tithonian		Upper Haynesville
	U. Kimmeridgian		Buckner (L. Haynesville)
	L. Kimmeridgian		Smackover
	Oxfordian		Norphlet
Middle Jurassic	Callovian?		
	Bathonian?		Lowville

Fig. 2

Industry reports outside the company estimates. A Shell geologist points out that ultimate recovery will depend on the areal extent of good porosity in the Smackover.

He notes the Smackover is not the usual carbonate in this area. Instead, it is a sandstone. The three fields are drilled on 1,280-acre units, because of the high cost of drilling and completion. Closer spacing, Shell says, likely would be uneconomic.

Shell estimates cost of drilling the wells averages in excess of \$2 million. Completed well cost is in the neighborhood of \$5 million.

"Interconnection of reservoir pore space is good the wells are highly productive, as we have no reason to believe we must drain a large area," the Shell geologist explains.

Shell has three deep gas wells in the Thomasville field, two in Piney Woods, and one in Southwest Piney Woods, the big daddy of Mississippi's deep producers.

It is also regarded as being the world's highest-pressure producing reservoir.

The 1 Ridgeway Management tested 39 Mcf of methane, hydrogen sulfide, and carbon dioxide from 21,998 to 22,250 ft. Bottom-hole temperature averages 385° F. and pressure 22,000 psi.

Shell ran a special 6%-in. casing with a body-wall thickness of 1½ in. and 1½-in. collar wall. A 19-ton well-head rated at 30,000 psi was installed. Shell has ordered two more of the \$250,000 trees for wells to be drilled in the area.

A company geologist expects at least one more well will be drilled in Southwest Piney Woods and possibly another well in Thomasville. Shell is in the process of completing the 5-A Cox, the second well in Piney Woods. It will require a 20,000-psi-rated tree.

Another rig is drilling a deep test for Shell northwest of Jackson in Yazoo County. The 1 Brown in 1-8a-4w was drilling below 17,500 ft at last report toward 19,500 ft in the Norphlet.

A Shell spokesman says the company plans to maintain a one-rig deep-drilling program in the Jackson area in the near future.

ern Rankin County, Miss.

In Mississippi, the McCoy group has been working three crews in Hancock County, one in Pearl River, and one in Jackson, the southeasternmost county in the state. Continental Oil Co. has been collecting seismic in Stone and Greene counties. Deep Mississippi drilling. Geologists say the Smackover and Norphlet drop out of economic reach in the deep part of the Mississippi salt basin in the eastern Mississippi.

However, Covington, Jefferson Davis, Jones, and Perry counties have yielded five Lower Cretaceous and Upper Jurassic discoveries recently at or below 15,000 ft.

Only deep Jurassic wildcat making hole in southeastern Mississippi is Petro Grande Inc.'s 1 McInnis in 34-3n-63, Greene County. At last report, operator was below 17,000 ft on the 22,500-ft Norphlet probe.

Only four wells have penetrated deep Jurassic rock in Mississippi's toe to the Gulf of Mexico.

Farther northwest, Getty is drilling below 17,000 ft on its third well in the South Sumner and area of northeast-ern Covington County and northwest-ern Jones. The project is permitted to 19,000 ft.

Getty completed the South Sumner and Haynesville-Buckner discovery below 18,581 ft in 1974 and offset the strike with a Cotton Valley discovery below 16,236 ft earlier this year. The discovery flowed at the rate of 984 bo/d.

The Cotton Valley tested 432 bo/d and 250 Mcf. Getty, Sun, and several independents have interests in this acreage.

Florida Gas Exploration Co. also has three new deep discoveries — Bassfield in Jefferson Davis county, Seminary in Covington County, and the 1 Rebecca Hill, 13 miles southeast of Getty's South Sumner and wells.

Meanwhile, Skelly has permitted an outpost for South Williamsburg field, a Hossion find about half way between Bassfield and Seminary.

Union has completed two wells in the Tiger field in Perry County and is in the process of completing a third. Hossion sands at about 15,000 ft yield low-volume gas rich in liquids. One outpost attempt was dry.

Deep, sour-gas wells. Farther north-westward, Shell has completed five costly wells below 20,000 ft on three structures bearing sour gas in south-

"We have other prospects to test in southern Mississippi and Alabama but probably will not be getting to them for several months," a Union geologist says.

A Getty explorationist says a number of anticlines as large as 2-4 miles across remain to be explored. The largest of these are apparently generated by salt swells.

Low-relief "turtles" also are prospective, he says. These anticlines are negative areas between anticlines pushed upward by salt swells. These negative areas have been compressed and folded by the salt.

Two rank wildcats, South and east of the Chunchula-Kiam area, two more deep Jurassic probes are being drilled by Saga Petroleum U.S. Inc. and Texaco Inc.

Saga is drilling below 14,000 ft on a 22,000-ft Norphlet project in 11-6-4w, Mobile County. This is the southernmost deep test in Alabama. Near-Betty Joe Anderson is 23-3-4w, about 16 miles to the north. It was plugged and abandoned last summer at 20,089 ft, reportedly having encountered metamorphics below the Louann salt.

Forest since has drilled another dry Norphlet 48 ft.

Smackover and Norphlet were reported to have encountered tight

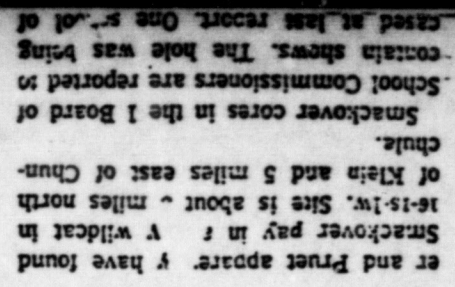
Watson's to 16,222 ft. Both are reported to have encountered tight

Smackover and Norphlet. Because of the unpredictability of porosity and permeability in the area, a Getty explorationist warns that assessing potential is not only difficult but speculative.

More seismic shooting. Meanwhile, companies are gathering more seismic to define new structures and to improve definition of previously indicated events.

Seven crews were shooting line in mid-April in southwestern Alabama and southeastern Mississippi. Getty and Amoco Production Co. each had a crew in Mobile County. In neighbor-

ing Baldwin County, Getty had two



Union has about 22,000 acres in the fourth of the Chunhua structure. Some of the leases, however, may be off the structure.

The Alabama Oil & Gas Board has authorized a 33-section outline and 640-acre drilling units for Chunhua. The field probably will commence production by the end of the year. Equipment is on order, but production plans have not been settled by the interests.

Getty's big strike, The Peter Klein discovery, 7 miles southeast of Chunhua, is on a separate anticline structure also associated with movement of the Louann salt.

The Klein well had a big bonus — 214 net ft of pay in the Norphlet sandstone in addition to 100 ft of net pay in the Smackover carbonate. The latter is 200 ft or so higher than the Chunhua Smackover.

Norphlet flowed gas and condensate at the rate of 3.4 MMcfd and 1,266 b/d through a 1/4-in. choke from perforations at 18,180-18,200 ft. Tubing pressure was 2,400 psi. Smackover tests: 6.2 MMcfd and 2,166 b/d through 17/64-in. choke from 18,042-62. Getty reports the gas and 60°-gravity condensate is low in sulfur.

Getty calls the Klein well its most significant drilling operation of 1974. The company owns 100% in the well and has leases on 11,700 net acres in the vicinity, covering 95% of the 14 sq-mile prospect.

Two 18,700-ft confirmation wells at the outcrop in 10-25-1w, about 1 mile southwest of the Klein, and two extension attempts in 34-15-1w and 16-25-1w, about 1 mile south of the Klein, are being drilled. The next two extension attempts for the next south and west in 10-25-1w and 4-25-1w now drilling below 17,000 ft to the south and west in 10-25-1w and 4-25-1w. The company is waiting to lay out the outcrop in 10-25-1w.

The company is waiting to lay out the outcrop in 10-25-1w. The company is waiting to lay out the outcrop in 10-25-1w.

Getty and Union say five rigs were committed to the area so development could proceed as rapidly as possible and delays in recovering some of the well expense would be shortened. However, leases on record approximately 1 month ago indicated that the year terms expire on many of the leases in 1976 and 1977. And a few of the Getty leases would expire late this year if not drilled or if additional arrangements were not made.

Key wildcat, independent Mesback

ward slightly as the field is produced. About 10 days ago, Unocal ran pre-perforated liners in two extension attempts in Sections 15 and 17 and acidized the formation. Union was conducting flow tests last week. Two more locations are permitted for extension attempts farther east and west. However, the site in adjacent section 18 to the west may be bypassed for a new location two sections farther to the west, a Unocal spokesman tells the Journal.

Meanwhile, Getty Oil Co. is drilling below 9,000 ft on an 18,800-ft northern outcrop in Section 9. About 4.5 miles to the northeast, Unocal drilled an 18,759-ft wildcat in 31-15-1w which encountered shows in the Silgo and Smackover. However, pays were tight, and the hole was plugged and abandoned.

Unocal's second Chunhua project in 22-15-2w also encountered good indications in the Smackover but was temporarily abandoned because of downhole difficulties. This well is about 4,000 ft southwest of the Chunhua discovery.

Unocal says it will reenter the hole and work it over to determine whether or not it will be a producer.

Methods changed. Formation difficulties prompted Union to modify drilling and completion methods in recent Chunhua wells. Drilling fluids tend to wash out the bore hole in the Smackover dolomite, a Unocal man explains. Washouts have been bad enough that hole calipers cannot measure the bore. Inability to gauge the size of the bore creates uncertainties in interpreting electric logs. And the Smackover dolomite washouts also lead to the casing-bore annulus being filled with so much cement that perforation of the formation is impeded.

So the operator now drills into the last few feet of the basal Buckner anhydrite and sets pipe before proceeding into the Smackover. Then Unocal converts to an oil-based mud and reduces pump pressure and annulus scouring. Next, operator cores into the Smackover. Thus callipers are able to measure the true diameter of the well bore.

Union has a 77% interest after paying out in a 16-section interest block containing current Chunhua completion. Other interests are held by Getty, Phillips Petroleum Co., the Davis McCoy group, and Cities Ser-

Manville, deep drilling in southeastern Mississippi continues to turn up Lower Cretaceous and Upper Jurassic production.

And in the Jackson area, Shell Oil Co. plans additional development drilling in three deep, sour-gas fields. The company has achieved an engineering triumph in Southwest Piney Woods field, believed to be the world's most difficult gas reservoir to harness. Chunhua field. How big is it? Florida's Jay field commonly is used as a yardstick. Unocal modifies the comparison, saying Chunhua has the potential of being as large as Jay.

The Chunhua anticline is very large, Unocal says, declining to describe how large. "Everybody's a little bit skeptical about predicting reserves," a company geologist declares, "because we are dealing with Smackover. The Smackover has been known to disappoint. There's nothing blanket about porosity and permeability."

Another Union spokesman believes Chunhua ultimately will be a large field with a few nonproducing spots where the Smackover carbonate is too tight to be commercial.

At present, production is indicated under roughly 4-7 sections, depending on how optimistic or conservative one wishes to be. That's about a fourth of the 14,000 acres covering Jay's productive area. Jay Smackover is as much as two to three times thicker than at Chunhua, however. Reserves recently were revised upward to in excess of 345 million bbl.

Smackover dolomite at Chunhua has been found up to 100 ft thick so far and has produced from intervals between approximately 18,400 and 18,510 ft in four wells. Completions are in adjacent Sections 16, 20, 21, and 22 in 15-2w, northern Mobile County.

The four wells flow tested at rates ranging from 2 MMcfd and 819 b/d to 3.2 MMcfd and 1,158 b/d through 1/4-in. chokes. Tubing pressures ranged from 1,520 psi to 2,590 psi.

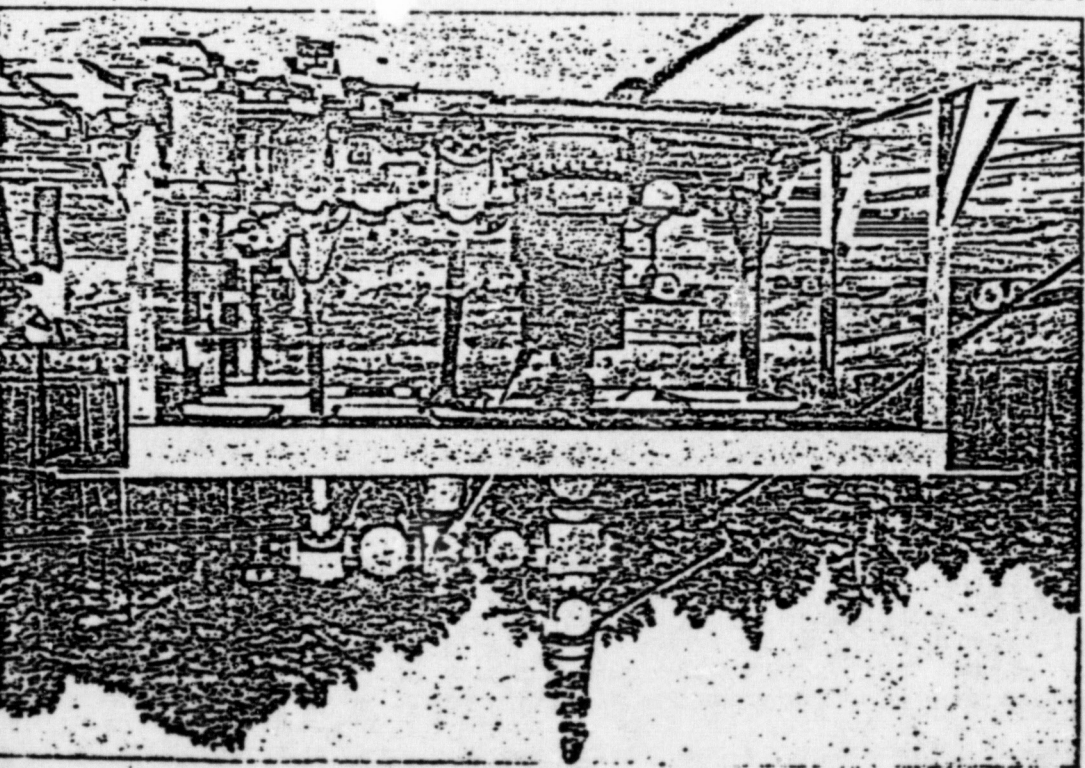
Rare reservoir. Chunhua is a Smackover rarity. Union reports the gas contains only 50 ppm of hydrogen sulfide (a trace percent in a volume comparison) and about 1.5% volume condensate contains only 65 ppm H₂S. And Union says it's possible the condensate will require a treatment plant. tests of separator liquids. However, the gas will require a treatment plant. And Union says it's possible the condensate will require a treatment plant.

And Union says it's possible the condensate will require a treatment plant.

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Major finds spur score of Southeast U.S. deep tests

A 30,000-PSI-RATED wellhead and a special heavy-wall tubing harness Shell Oil's 1 Ridgeway Management, a deep, high-pressure, sour-gas well in Rankin County, Miss.



NEWS

3067

DAN McNABB
Gulf Coast News Editor

SIGNIFICANT Jurassic and Lower Cretaceous strikes in 1974 and early 1975 have stoked new fire into a deep-drilling play stretching from near Mobile, Ala., northwestward to the vicinity of Jackson, Miss.

Earlier this month, about 20 projects aimed at targets below 15,000 ft were in various stages of drilling and completion. Action focuses in northern Mobile County, about 15 miles north of the city of Mobile.

Six big rigs are on location in a triangular area about 7 miles by 6 miles by 9.5 miles. In the northwest corner of this 21-sq-mile triangle, three rigs are on ex-

tension attempts in Chunichula field, discovered by Union Oil Co. of California in December 1973.

Two more rigs in the southeast corner of the triangle are making hole on outposts to Getty Oil Co.'s prolific Peter Klein discovery.

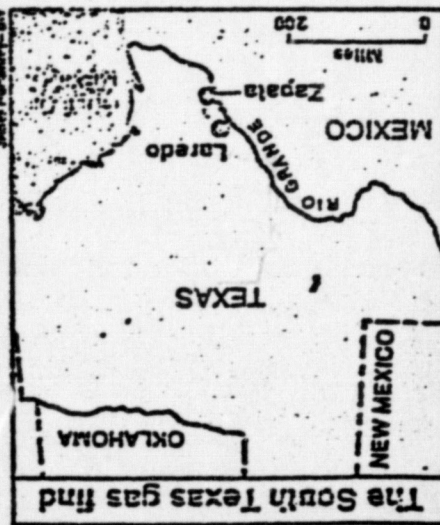
Robert Mosbacher and Chesley Pruett are getting ready to test a key wildcat about 5 miles north of the Klein well and 5 miles east of Chunichula.

The Chunichula and Klein strikes are generally regarded among southern U.S. explorationists to be the most important onshore strikes in the Lower 48 since the Jay field discovery in 1970. And some of the more optimistic geologists expect that one or the other or perhaps both may be even larger than Jay.

Drilling when the price is right

In 1964, a well hit a highly promising gas discovery near the border town of Laredo in South Texas. But the gas was trapped at extreme pressure in puzzling geology, making it too expensive to drill development wells when gas was selling for only 13¢ per 1,000 cu. ft. Then, only two more wells were attempted in the nine years following the discovery.

Today, though, the 4½-mi. area south of Laredo is suddenly attracting ward revisions of the estimated gas to be found in the Laredo fields. As the quick-ened pace, geologists are making up-ward revisions of the estimated gas to be found in the Laredo fields. As the quick-ened pace, geologists are making up-ward revisions of the estimated gas to be found in the Laredo fields. As the quick-ened pace, geologists are making up-ward revisions of the estimated gas to be found in the Laredo fields.



Oilmen point to the Laredo play as proof that big new gas supplies can be found and produced if the price is right. But they quickly add that the Laredo drilling boom could dry up as suddenly as it began if a proposed federal ceiling price of 70¢ per 1,000 cu. ft. is imposed on the interstate market. The reason: It costs \$400,000 or more to drill the 5,000-ft. to 7,000-ft. wells in the area. So far, one of every five holes drilled has been a duster. It will take an estimated 900 wells to fully exploit the fields. Says Mike E. Douglas, a San Antonio geologist: "If the price is forced down, producers are going to call time out."

son III (D-III), who would rather close the gap between interstate and intra-state prices by extending controls to include interstate sales. Along with Senators Warren G. Magnuson (D-Wash.) and Ernest F. Hollings (D-S.C.), Stevenson is sponsoring a bill designed to do just that. The bill would impose a national ceiling on all new gas, both interstate and intrastate, which would be set by the FCC in a range of 40¢ to 75¢ per 1,000 cu. ft. Smaller producers who market less than 10-million cu. ft. a year would be entitled to prices 50% higher.

Stevenson and such groups as the Consumer Federation of America contend that prices above 70¢ per 1,000 cu. ft. will not bring in substantial new supplies, and they back their claim with data from a surprising source: the Federal Energy Administration. The FEA's Project Independence study, they say, indicates that an 80¢ price would yield 18.12-trillion cu. ft. in 1985, while a 52¢ price would result in only a tiny bit more gas—18.17-trillion cu. ft. The FEA, phasing, charged, has discovered the figures and charges that Stevenson is making, reporting its data.

The Stevenson proposal has stirred a unique dispute between producers, pro-

While they favor deregulation of prices, interstate pipelines contend that the bill would at least help them buy onshore gas in the critical short-term situation. They add, however, that in long-term, the ceiling price is too low to provide a drilling incentive. Some industry sources predict a 30% to 50% drop in onshore gas exploration if the price is set at 70¢ per 1,000 cu. ft. But many interstate companies, afraid that regulation of interstate prices is the best they can hope for, agree with line Co. "At this point, doing some-

thing bad is better than doing nothing."

Strongly, charging that the regulation of the interstate market would be nothing short of insanity. "We should have learned by now that regulation of natural gas during the last 20 years has been absolute disaster," argues inde-

pendent Texas oilman George F. Mitchell, president of Mitchell Energy

On the other hand, proponents of deregulation argue that the consumer will suffer far more in terms of lost jobs and higher alternative fuel costs unless the worsening shortage of natu-

ral gas is eased by higher prices. And if it, they argue, would mean allowing the wellhead price, at least of new gas, to rise to whatever the market will bear. "Anything less," says Francis C. Allen, director of the FCC's Bureau of Natural Gas, "won't get the job done."

FCC report on the Federal Power Com-

missioner's role in the gas controversy.

turn to page 24.

you can make money drilling under-

1. At the last 15 months.

Interstate carriers and pipeline

states also argue that a ceiling on in-

terstate systems would result in severe

disruptions in the Southwest. "With all

the pipelines back East still running at

least 50% industrial sales, what you

would be doing is taking gas from an

industry in Texas, which normally is

not equipped for dual fuel, and giving

it to one on the East Coast, which nor-

mally is equipped for dual fuel," says

the chairman of Houston Natural Gas,

Robert R. Herring.

Not all legislators favor extension of

gas price controls, and the debate will

soon get formal airing. This week, the

Senate Commerce Committee voted in

favor of placing new interstate gas

sales under federal controls, though the

committee also voted to loosen price

regulations on smaller producers. The

bill now goes to the Senate floor, where

a broad confrontation between oppo-

nents and proponents of deregulation

is inevitable.

Staggering demand. The issue boils down

to whether the nation is willing to sus-

tain the economic shock of paying the

free-market price for gas after two

decades of artificially restrained prices.

Producers and interstate pipeline

executives downplay the impact that

deregulation would have on the burner-

tip price of gas. They claim the price

would rise only 6¢ to 10¢ annually for

perhaps 10 years, assuming that inter-

state prices would rise to about the

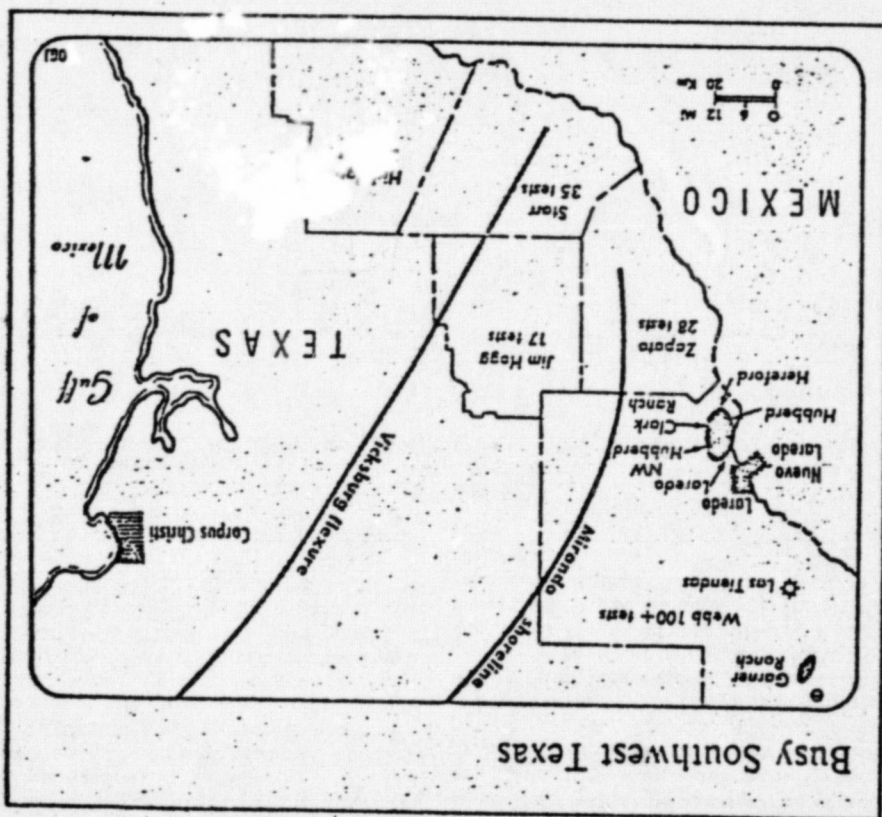
level of today's interstate prices.

But no one knows how high the price

of gas would go as a result of deregula-

3065

Southwest Texas drilling activity flourishes



At the end of 1974, Southwest Texas was one of the busiest areas on the drilling map of the U.S.

Just before the holidays, there were

209 active locations (drilling, rigging

up, waiting, etc.) in just five of the

counties of Texas Railroad Commis-

sion District 4. The other counties,

not listed on the map, were also very

active, but the focal point of the cam-

paign seems to be in the Laredo area

along the Rio Grande.

From Laredo, Exploratory and de-

velopment work in far Southwest

Texas begins its sweep 50 miles or

more northwest of Laredo, hence

downstream along the Rio Grande

past Starr, Zapata, and into Hidalgo

counties.

There are more than 100 active

drilling sites in Laredo's immediate

area, most of them from the city

limits southeast toward Zapata. One

of the most active newly opened fields

is at Clark Ranch, 12 miles south of

the city. Consolidated Oil & Gas Co.

recently completed its sixth producer

in this Webb County plume. Flow at

the 1 Ruiz was 3,459 Mcfd and 24 bbl

condensate through one zone, 8,400

Mcfd through another. This was a

dual completion in the Midway Lower

Eocene formation at 6,206-6,306 ft. The

upper stage was completed at 5,532-44

ft. Location is 2 miles west of 1 Pre-

vost, a dual gas well in the Wilcox and

Midway Eocene and about 2 miles

northeast of Hereford field, a Wilcox

producer of gas.

Good Hope Refineries has two Wil-

cox discoveries south of Laredo in

Webb County. The 1 McKendrick

flowed 4,746 Mcfd and 160 bbl con-

densate daily from pay at 6,804-6,915

ft. This opened Northwest Hubbert

field. Good Hope 1 Hereford, 2 miles

southeast, flowed 9,466 Mcfd and 84

the reports.

Hidalgo on downriver is very active

with 29 active drilling locations on

ing sites.

County is busy with 17 assorted drill-

Ross, La Copita, and others. Jim Hogg

Arkansas City, Zim and Zim West,

Gregg Wood, Rincon, El Benadito,

Kennard, Coastal, Remco, McMoran,

with interest at Roma, North Sun,

sites. Starr County has 35 active spots

and at other Webb County wildcat

Zimet, Gardner Ranch, Glen Martin,

Hermanos, Tom Walsh, Las Tiendas,

Northwest, H. E. Clark, La Cruz, Dos

Hereford, Hubbert and Hubbert

Zachry Ranch, Laredo, Jasper-Webb,

There is activity at Clark Ranch,

today's Southwest Texas drilling.

1. The companies with which I am associated believe they own more modern geophysical data within the Deep Anadarko Basin than any other company.
2. Kansas, Oklahoma and Texas Railroad Dis-
3. Colorado, November, 1971.
4. School of Mines Foundation, Inc., Golden, Colorado, November, 1971.
5. The companies with which I am associated believe they own more modern geophysical data within the Deep Anadarko Basin than any other company.
6. Oil and Gas Journal, September 16, 1974.
7. Oil and Gas Journal, February 24, 1975.
8. The Oklahoma Energy Advisory Council was brought into being by the Oklahoma State Senate in 1973 to review the full spectrum of Oklahoma's energy.
9. The American Association of Petroleum Geologists defines a "significant field" as one either having produced or having reserves capable of producing 6 BCFG.
10. A management and consulting firm in Oklahoma City, Oklahoma.
11. 1977-1980 dollars and, therefore, conservative if inflation is substantially slowed.

1. Prepared by the Potential Gas Committee

References

save American customers and their Congressmen who can put at the top of his list for energy! It is your duty as President Ford has correctly and wisely all humans possible to help achieve the legislation (for the third time). We must act now and do of new reserves must be passed by legislation consumers and the Congress that deregulation unified efforts by our entire industry to tell the new exploratory budgets and renewing our development with a substantial portion of the recompleting deep onshore exploration and We can meet that challenge by immediately supply.

from the deep zones in the traditional areas of calating the pressure for quick deliverability projects and LNG projects, thereby rapidly es- duction, the Arctic system, coal gasification many delays in offshore development and pro- To conclude, I submit that there will be transportation cost will be about \$10 billion.

usually, The new capitalized trans- mid-1976) it will commence producing about 1.4 TCF annually.

date of July 1979 (based on Canadian and Fed- eral Power Commission regulatory approval by

Production from deep and ultra-deep natural gas wells can be connected to existing natural gas pipelines. This significantly reduces the time from which drilling is commenced and when natural gas is delivered to the burner tip. For example, the Bureau of Mines has estimated that historically there has been a five year time lag between leasing and first gas production in offshore areas. Natural gas from onshore areas with deep and ultra-deep super well capabilities can be delivered to the consumer within 24 months from the initiation of leasing.

To put the time and cost elements in perspective, I have made the following comparison — a projected deep development program in the Deep Anadarko Basin with the Arctic Gas Project (A chart showing various deliverability factors against time with an addendum indicating our assumptions is attached to this presentation.)

By mid-1980 in the Deep Anadarko Basin it is possible to drill 500 wells, 300 successful, at a cost of between \$2.5 and \$3 billion. By mid-1980 these 300 successful wells will be delivering to existing systems between 1.3 and 2 TCF annually. mid-1979 (the currently projected delivery date for the Arctic system) some of these wells will have already produced 1.5 to 2 TCF into existing systems.

If the Arctic system makes its initial delivery

as high as 50 years for others. You, typically, have gas reserves of 8 to 10 years at your present consumption rates. These reserves are coming from wells that will take 15 to 20 years to deliver this gas. Thus, deliverability is becoming an increasingly difficult problem which you are lending to meet by the increasing use of gas storage reservoirs. Your problem is declining deliverability — operating with partially empty facilities.

Based on 1973 data, when the typical line was reasonably full, the average wellhead price was approximately 27¢ per Mcf and transmission and distribution costs to a typical consumer were about 51.25¢ per Mcf, making the cost to a consumer's meter total about 51.52¢ per Mcf for a typical East or West Coast consumer. Assume only a drop in volume to 60% of line capacity with wellhead prices pegged at the 1973 average of 27¢ per Mcf. The decline in compressor fuel used for transmission is probably offset by the increased fuel used for gas storage reservoir compression, so that total line costs stay fixed. The resulting cost to the consumer's meter goes from 51.52¢ per Mcf to 52.35¢ per Mcf. If depreciation is changed to a life equal to your gas reserves, the cost to the consumer's meter, of course, goes sharply higher. It would seem that the only reasonable basis on which you could justify your low depreciation rates is the assumption that further gas reserves will become available down through the years. If Congress regulates the price of natural gas by statute, all reasonable basis for this assumption will vanish, and I would think you would expect your auditors to change your amortization rates to such a degree as to produce severe annual losses.

What your companies need are substantial new deliverable reserves. From the consumer's point of view, from your shareholder's point of view, and for your very own survival, new deliverable reserves are needed promptly by your systems.

Clearly the "regulatory experience" has failed not only this country but the consumer, for the natural gas consumers of this nation are this very minute.

1. Faced with a 10% national curtailment this year and rapidly declining supplies in the midst of vast undeveloped lower 48 natural gas reserves.

2. Paying higher costs for less gas caused by the necessity of inefficient amortization of the billions of dollars of remaining investment in existing pipelines.

3. Faced with the prospect of conversion or premature disposal of billions of dollars of natural gas appliances.

4. Paying \$3.00 to \$4.00 per Mcf for synthetic gas when natural gas could be meeting that demand at lower costs.

Any further regulation or "re-regulation" of natural gas sales at the wellhead will:

1. Push this country further into recession.

2. Add to inflation while experiencing short-ages of supply.

3. Create years of first constitutional in the courts over a myriad of constitutional matters.

4. Create years of legal confrontations in the courts and before the regulatory bodies over a complexity of details impossible to legislate or regulate.

5. Add years to the intolerable "regulatory lag," presently in existence.

6. Promote irreconcilable "regionalism" within the country and with it divisiveness among the people of this country.

Whereas, the suspension of regulation of new wellhead natural gas sales will:

1. Have a major positive impact in leading our economy out of recession.

2. Increase domestic supplies leading toward a balance of supply and demand at non-inflationary costs to the consumer.

3. Promote cooperation between the great institutions of this country, promote cooperation between the supplier and producer regions of this nation, and promote a spirit of cooperation, good will, and togetherness among the people of America at a time when we can least afford any increasing negative pressures from within.

The remainder of my remarks must assume deregulation of new gas and will be directed primarily toward the question consumers are most interested in — how much gas will be available over the next five to seven years?

As you are aware there is a wide variance in estimates of onshore potential for the lower 48 which range from 65 to 1,177 TCF. Estimates at the low end of that range are more than merely unrealistic, they are extremely dangerous if allowed to be weighed in the decision making process of those charged with the responsibility of formulating sound energy policy for our country. I feel a strong responsibility to contradict these estimates, partly because I continue to devote all of my resources toward the gas exploration business and believe all of us with special knowledge must take every responsible action possible to bring about quickly a sound energy policy for the United States.

One of the realistically conservative onshore lower 48 estimates is 550 TCF by the Potential Gas Committee. Of this 550 TCF of potential recoverable natural gas, approximately 25% or 137 TCF is estimated to lie between the depths of 15,000 and 30,000 feet. 25 TCF of that is estimated to be recoverable from wells deeper than 15,000 feet in Region 1 North. I am familiar with the Deep Andarko Basin which includes all its potentially productive sediments below 15,000 feet. Based on my knowledge of the geology, geophysics and reservoirs of the Deep Andarko Basin, the minimum recoverable reserves are 50 TCF — twice the conservative estimate of the Potential Gas Committee. I estimate for Region 1 North and 77% of Mobil's estimate for the entire onshore lower 48!

The president of the A.G.A. has also taken issue with unrealistic reserve estimates made by the National Academy of Sciences. Mr. Hart charged that the Academy did not study natural gas itself but merely "calculated natural gas by some assumed factor applied to its detailed work done for crude-oil resources." Hart "strongly condemned" the Academy's judgment that the United States would run out of natural gas by 1980.

of natural gas in 25 years and James S. Cross (vice-president of the American Petroleum Institute) said "we are not running out of energy" but he warned "we are running out of time." The Oklahoma Energy Advisory Council in its final report estimated potential reserves of 35 to 100 TCF for Oklahoma alone, most of which will come from the Deep Andarko Basin. If one assigns validity to the Oklahoma Energy Advisory Council figures (and I am one who believes in local experts) then the recoverable gas for Region 1 North may be as high as 140 TCF, an increase of 67% over the 84 TCF estimated by the Potential Gas Committee.

Large amounts of gas can be produced at exceedingly high rates from wells which can be called "super wells" — most of which are in the deep category. These "super wells" can rapidly arrest declining deliverabilities in existing systems. Super wells have the unique distinction of producing in only one year an amount of gas equal to the amount of gas used to decline a "significant field" — six BCF.

A study resulting in identification of existing super wells was prepared by the Resource Analysis and Management Group and shows that in 1974 there were at least 122 such wells, each of which produced more than six BCF of natural gas. Approximately 75% of these wells produced from depths below 15,000 feet. Deeply the more heavily explored Delaware Basin contained approximately 60% of the group while over 15% were in the Andarko Basin with the remainder elsewhere. The wells are young — about 34 of the group had first production in 1969 or more recently.

The super wells capability for production is almost unbelievable. For example:

- 45 of these wells can produce more energy annually than is produced by the entire Tennessee Valley Authority.
- One average super well can supply the gas needs (including industry) of a typical town of 70,000 people.
- The average super well could heat in the winter and cool in the summer 37,500 homes each containing 1,500 square feet.
- The average super well could meet the energy requirements of over 75 hospitals, each caring for about 500 in-patients.
- Three of these wells can produce as much energy as two 700 megawatt electric generating nuclear plants (these plants would cost over \$1 billion).

Technical accessibility of natural gas depends only on transmission capacity, storage capacity and total well deliverability. This is not true for our petroleum, tar sand, oil shale, uranium, thorium, geothermal or coal energy resources which require intermediate processing or vast new systems and plants.

The majority of potentially recoverable natural gas reserves from depths of 15,000 feet or greater are located in areas which already are served by major interstate and interstate natural gas pipelines. The most significant onshore deep or ultra-deep reserves are believed to lie in the Andarko Basin, the Permian Basin, the Texas Gulf Coast and Mississippi Embayment and possibly some Rocky Mountain basins and the Appalachian Basin.

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UNITED STATES
DEPARTMENT OF THE INTERIOR

DRAFT ENVIRONMENTAL STATEMENT

Volume 2 of 4

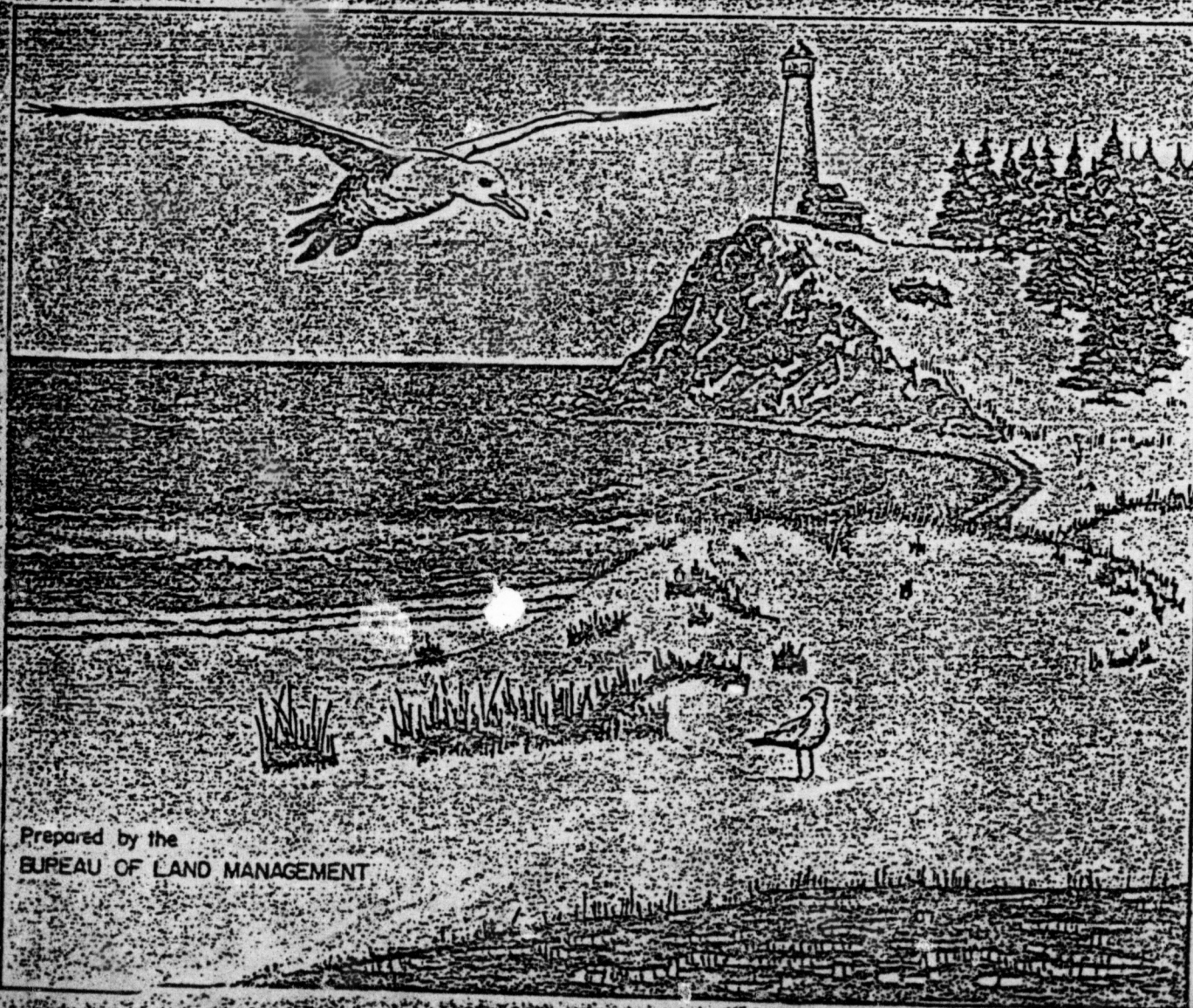
Proposed

1977 OUTER CONTINENTAL SHELF

OIL AND GAS LEASE SALE

OFFSHORE THE NORTH ATLANTIC STATES

OCS SALE No. 42



Prepared by the
BUREAU OF LAND MANAGEMENT

961

Table III-34a

Land Use Requirements of OCS-Related Facilities
Estimated to Result from Proposed Sale No. 42

1. SURFACE AREA FOR FACILITIES WHICH MUST BE
PROVIDED IN THE REGION:

	Number	Hectares/Facility (Acres/Facility)	Total Hectares (Total Acres)
Onshore Operations Base ¹ (At peak activity period, about 1985. Low area figure is for low resource case, high area figure is for high resource case.)	2-3 (Port areas)	12-14 (30-35) (per port)	24-42 (60-105)
Gas Processing Plants ² (500 to 700 million of/d capacity each. Total area figure assumes 30 hectares or 75 acres per facility.)	1-2	8-30 (20-75)	30-60 (75-150)
Pipeline Terminal and Storage Facilities ³ (if any)	1-3	16 (40)	16-48 (40-120)
Service Support Companies ⁴ (Based on total requirements estimated for 10-20 rigs op- erating at any one time.)			15 (38)

SUBTOTAL: 85-165 hectares
(213-413 acres)

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Table III-34a continued

2. AREA FOR OTHER FACILITIES WHICH MUST BE PROVIDED IN THE REGION:⁵

Onshore Oil Pipelines (if any)

24-40 Kilometers
(15-25 miles)

15-30 meter
(50-100 feet)
wide corridors

70-120 (180-300)

Onshore Gas Pipelines (To
gas processing plants only.)

16-40 kilometers
(10-25 miles)

15-30 meter
(50-100 feet)
wide corridors

50-120 (120-300)

SUBTOTAL: 120-240 hectares
(300-600 acres)

3. SURFACE AREA FOR FACILITIES WHICH MAY BE REQUIRED OR STIMULATED IN THE REGION:

Pipecoating Yards⁶

40 (100)

Platform Construction Yards

Conventional Steel Platforms
Concrete or Gravity Structures

400 (1000)
40 (100)

Assuming one of each of the above is established in the region.....SUBTOTAL: 480 hectares
(1200 acres)

TOTAL AREA WHICH MAY BE REQUIRED FOR OCS-RELATED
FACILITIES IN THE NORTH ATLANTIC REGION⁷

663-885 hectares
(1713-2214 acres)

Footnotes for Table III-34a

¹Operations bases support off shore activities. For the low case, maximum activity level (in terms of land consumption) is assumed to be 10 exploratory and development rigs working, 2 platforms installed and 3 platforms producing. For the high case, maximum facility level is assumed to be 20 exploratory and development rigs working, 3 platforms installed and 8 platforms producing. This is a result of the overlap in OCS operations phases. The total amount required is assumed to be divided among two to three ports. Acreage requirements per activity were adapted from NERBC 1975(c). That report provides a range of acreage required per activity supported. The low end of the range was used for a large number of facilities supported (to account for economies of scale) and the high end of the range was utilized for only a few activities being supported.

²CEQ 1974, estimated that a gas processing plant requires only 20 acres, while NERBC 1975 (c) estimates that up to 75 acres, including a buffer area, would be required for processing plant.

³Such a facility would be required if a refinery(ies) is built in New England and oil from the OCS were to be transported to it (them) via pipeline.

⁴A breakdown of facilities included in this figure may be found in Table III-34b, which also indicates acreage per facility. No more than a total of 10 to 20 exploratory and development rigs are anticipated to be working at any one time as a result of the proposed sale. This figure represents the amount of these activities estimated to be required to service this range and the acreage associated with it. (From Offshore Operators Committee).

⁵Pipelines do not necessarily require surface acreage to be dedicated for use as pipeline corridor.

⁶Pipecoating facilities will be required for any marine pipelines on the Atlantic coast. However, one such facility may service more than one operating area on the coast, so that a facility may or may not be located in New England.

⁷This figure may not be all inclusive. Other small facilities not enumerated here may also result from the proposed sale. This figure represents a best estimate of anticipated significant facilities.

Table III-34b

Estimated Land Use Requirements of
Industry Anticipated Service Support Facilities¹

Facility			Locational Requirements
	Hectares	Acres	
Mud Supplier	1.5	4.0	Inland water docksite with ocean access; industrial zoning.
Cement Company	2.0	5.0	Inland water docksite with ocean access; highway and rail access; industrial zoning.
Wireline Company	2.5	6.0	Industrial zoning; highway access.
Gas Lift Company	0.2	0.5	Industrial zoning; highway access.
Logging and Perforating Company	1.5	4.0	Industrial zoning; highway access.
Rental Tool Company	1.4	3.5	Industrial zoning; highway access.
Wellhead Equipment Company	0.6	1.5	Industrial zoning; highway access.
Machine Shop	0.4	1.0	Industrial zoning; highway access.
Trucking Firm	2.0	5.0	Industrial zoning; highway access.
Supply Store	0.8	2.0	Industrial zoning; highway access.
Downhole Equipment Company	0.8	2.0	Industrial zoning; highway access.
Diving Service	2.0	0.5	Industrial zoning; highway access.
Welding Shop	0.8	2.0	Industrial zoning; highway access.
Fishing Tool Company	0.4	1.0	Industrial zoning; highway access.
Cementing Company	2.0	5.0	Inland water docksite with ocean access; highway and rail access; industrial zoning.

¹Other small companies may also be needed or stimulated by OCS development. However, these are regarded by industry as the major ones in terms of employment and land use requirements. Information from Offshore Operators Committee (personal communication, 1975).

utilized for facility siting and other land use requirements, less undeveloped land would need to be dedicated to developed uses.

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Since the economic analysis indicates less substantial population increases for northern Massachusetts and coastal New Hampshire, as a result of the proposed sale, a different assumption will be utilized. If 15,000 persons were to locate in the SENE subregion Ispwich-North Shore, and/or 15,000 persons were to locate in the Strafford Rockingham, New Hampshire coastal planning region, approximately 8 percent and 7 percent, respectively, of the identified developable land in these areas would be required.

Since population increases of this magnitude are not expected to be sustained, and all the levels of increases utilized above may not, in fact be concentrated to this degree, lesser amounts of land would probably be required, even with high land consumption rates, in any given planning region.

Summary

Adequate suitable land for development necessitated by OCS activities and induced population increases probably exists in the North Atlantic coastal region. The cumulative maximum land use requirements estimated to result from the proposed sale is 5160 hectares (12,750 acres). The maximum land use requirements for

OCS-related facilities alone is estimated at between 663 and 885 hectares (1713 and 2214 acres). The analysis indicates that, assuming maximum concentration of induced population, at a maximum, 17 percent of the identified developable land in any planning region would be required as a result of the proposed sale.

Facility siting or rapid, uncontrolled growth could result in land use patterns which are not desired by communities and development could encroach upon areas for which agricultural, recreational or other uses are thought more desirable. The extent to which this occurs will be a function of the types of controls evoked by state and local governmental jurisdictions.

As indicated above, and in Section I.E.2., a variety of controls are available at the state level, in addition to local zoning and other controls, to regulate facility and other development. In some cases, these may be invoked to amend or deny OCS-related facility proposals onshore.

Thus, although facility siting and population associated land requirements resulting from the proposed sale present a potential for adverse land use impacts if uncontrolled, little adverse land use impact is anticipated.

